Appointment

From: Schwab, Justin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EED0F609C0944CC2BBDB05DF3A10AADB-SCHWAB, JUS]
Sent: 6/1/2017 4:07:19 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]; Patrick, Monique [Patrick.Monique@epa.gov]; Schmidt, Lorie [Schmidt.Lorie@epa.gov]; Minoli, Kevin [Minoli.Kevin@epa.gov]; Srinivasan, Gautam [Srinivasan.Gautam@epa.gov]; Zenick, Elliott [Zenick.Elliott@epa.gov]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Michael.Jenkins@PacifiCorp.com; megan.mckay@PacifiCorp.com; cstephens@agutah.gov; bbird@utah.gov; craiganderson@agutah.gov; Marinathomas@agutah.gov; ARobbins@jsslaw.com; schristiansen@parrbrown.com; Logan, Paul [logan.paul@epa.gov]; crabtree@deseretpower.com; Cathy.Woollums@PacifiCorp.com; Jeff.Richards@PacifiCorp.com; Chad.Teply@PacifiCorp.com; BRawson@rqn.com; Nate@uamps.com; H. Michael Keller [mkeller@fabianvancott.com]
CC: Greenglass, Nora [Greenglass.Nora@epa.gov]; Laumann, Sara [Laumann.Sara@epa.gov]; Dominguez, Alexander [dominguez.alexander@epa.gov]; Richards, Jeff [Robert.Richards@pacificorp.com]; Banks, Martin K. [marty.banks@stoel.com]; Stephanie.Talbert@usdoj.gov; Debra.Carfora@usdoj.gov; Lipshultz, Jon (ENRD) [Jon.Lipshultz@usdoj.gov]; Mason Baker [mason@uamps.com]; Megan Houdeshel [mhoudeshel@parrbrown.com]

Subject: Utah Regional Haze/Call-in Conference phone and code/Ex.6
Location: DCRoomARN4045/DC-Ariel-Rios-OGC

Start: 6/6/2017 5:00:00 PM
End: 6/6/2017 7:00:00 PM
Show Time As: Tentative

This meeting is being held at EPA's HQ, in the General Counsel's conference room. The address is 1200 Pennsylvania Avenue NW, Washington, D.C. 20460. We are located directly above the Federal Triangle metro station. If driving, please come to the middle of 12th Street NW/DC, between Constitution and Pennsylvania avenue. Then walk towards the alcove. Please come into the William Jefferson Clinton North entrance on the right. When you arrive, please check in at the security desk. They will call the main line 202-564-8064 for someone to come and escort you to the conference room.

Appointment

From: Washington, Valerie [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=9D031C02CE3A416DAD0D421EE998D5A3-VWASHING]
Sent: 5/18/2017 7:16:57 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; david.kunz@arkema.com; Beck, Nancy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=168ecb5184ac44de95a913297f353745-Beck, Nancy]; allen.karpman@arkema.com
CC: BERNSTEIN Rebecca [rebecca.bernstein@arkema.com]

Subject: EPA SNAP Regulations and General TSCA Implementation
Location: 1200 Pennsylvania Avenue, NW North (3415) Call Personal Phone / Ex. 6 or escort

Start: 5/24/2017 2:00:00 PM
End: 5/24/2017 2:30:00 PM
Show Time As: Busy

Appointment

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 6/27/2017 2:06:34 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; joanna.foust@daimler.com
CC: Bolen, Brittany [bolen.brittany@epa.gov]; Dravis, Samantha [dravis.samantha@epa.gov]; Kime, Robin [Kime.Robin@epa.gov]; jake.jones@daimler.com; william.craven@daimler.com; Letendre, Daisy [letendre.daisy@epa.gov]

Subject: Daimler North America / EPA
Location: 1200 Pennsylvania Avenue, NW (North) - Room 3528 WJCN

Start: 7/5/2017 6:00:00 PM
End: 7/5/2017 6:30:00 PM
Show Time As: Busy

Location: 1200 Pennsylvania Avenue, NW (North) - Room 3528 WJCN

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.

EPA Contact: For an escort from Security to the meeting call Personal Phone / Ex. 6

Contact:
Joanna Foust
General Manager--Federal Affairs
Daimler North America Corp.
1717 Pennsylvania Avenue, NW Suite 825
Washington, DC 20006
ph: 202-649-4506
cell: 202-281-9109

Appointment

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 7/17/2017 7:40:36 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Birsic, Michael J. (MPC) [mjbirsic@marathonpetroleum.com]; tjpeterkoski@marathonpetroleum.com
CC: Walas, Fred (MPC) [fawalas@marathonpetroleum.com]

Subject: Call - Marathon / EPA (re: Ozone)
Location: Conference Line: Personal Phone / Ex. 6

Start: 8/1/2017 2:00:00 PM
End: 8/1/2017 2:30:00 PM
Show Time As: Busy

Appointment

From: Washington, Valerie [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=9D031C02CE3A416DAD0D421EE998D5A3-VWASHING]
Sent: 5/1/2017 7:31:04 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; 'sjshimberg@sjsolutions.biz' [sjshimberg@sjsolutions.biz]; 'mimi.braniff@delta.com' [mimi.braniff@delta.com]
CC: Ruggiero, Christopher [christopher.ruggiero@monroe-energy.com]

Subject: Following up on Patrick Davis' introduction
Location: William Jefferson Clinton Building 1200 Pennsylvania Avenue, NW Please call Personal Phone / Ex. 6 or escort

Start: 5/10/2017 6:30:00 PM
End: 5/10/2017 7:30:00 PM
Show Time As: Busy

Appointment

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 8/11/2017 9:52:11 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Shepherd, Ray [rayshepherd@peabodyenergy.com]
CC: Hort, Gregory [gregory.hort@lazard.com]; Forkin, Patrick [PForkin@peabodyenergy.com]; Novosel, Mary L. [MNovosel@peabodyenergy.com]; Krutka, Holly [HKrutka@peabodyenergy.com]; Taqi, Ali [ali.taqi@lazard.com]

Subject: Call - Lazard/EPA
Location: Conference Line: Personal Phone / Ex. 6

Start: 8/17/2017 9:30:00 PM
End: 8/17/2017 10:00:00 PM
Show Time As: Busy

Conference Line: Personal Phone / Ex. 6
Code: Personal Phone / Ex. 6

Make up meeting from August 10, 2017

Message

From: Edstrom, Brittanie [BEdstrom@hunton.com]
Sent: 9/5/2017 8:58:29 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Kime, Robin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=7ef7b76087a6475b80fc984ac2dd4497-RKime]; Hutchins, Eric M. [ehutchins@hunton.com]; Stanko, Joseph [jstanko@hunton.com]
Subject: RE: Ozone Meeting Confirmation on September 6th

My apologies. Can we also add Rachel Derby and Louis Baer from Portland Cement Association instead of Todd Johnston. Sorry for the confusion.

Brittanie

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 05, 2017 4:04 PM
To: Edstrom, Brittanie
Cc: Kime, Robin; Hutchins, Eric M.; Stanko, Joseph
Subject: Re: Ozone Meeting Confirmation on September 6th

Perfect thank you for this.

Sent from my iPhone

On Sep 5, 2017, at 4:01 PM, Edstrom, Brittanie <BEdstrom@hunton.com> wrote:

> Hi Alex,
>
> Thank you for your help in getting this scheduled. This is the list of attendees for tomorrow. Please let me know if you need anything further.
>
> Rachel Jones – National Association of Manufacturers
> David Friedman – American Fuel and Petrochemical Manufacturers
> Todd Johnston – Portland Cement Association
> Khari Cauthen –American Petroleum Institute
> Ted Steichen – American Petroleum Institute
> Hilary Moffett – American Petroleum Institute
> Stephen Higley – Marathon Petroleum Corporation
> Booth Jameson – American Chemistry Council
> Lorraine Gersham – National Oilseed Processors Association
> Timothy French – Engine Manufacturers Association
> Joe Johnson – US Chamber of Commerce
> Joe Stanko – Hunton & Williams LLP
> Eric Hutchins – Hunton & Williams LLP
>
> Best,
>
> **Brittanie Edstrom**
> Federal Affairs Adm Assistant

bedstrom@hunton.com
p202.955.1523

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037

hunton.com

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 05, 2017 11:16 AM
To: Edstrom, Brittanie; Hutchins, Eric M.; Stanko, Joseph
Cc: Kime, Robin
Subject: RE: Ozone Meeting Confirmation on September 6th

All –

Per my conversation with Brittanie we are confirmed for a meeting at HQ Wednesday, September 6 at 5:00PM.

Location: 1200 Pennsylvania Avenue, NW.

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg

EPA Contact: When all attendees are present, please call **Personal Phone / Ex. 6** or an escort from security.

Given the potential for a large number of attendees from your side, please send me a list of those who will be joining no later than 4:00 today as I will need to provide to security.

Anything else just let me know.

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Kime, Robin
Sent: Friday, September 1, 2017 12:02 PM
To: 'Edstrom, Brittanie' <BEdstrom@hunton.com>; Dominguez, Alexander <dominguez.alexander@epa.gov>

Cc: Hutchins, Eric M. <ehutchins@hunton.com>; Stanko, Joseph <jstanko@hunton.com>
Subject: RE: Ozone Meeting Confirmation on September 6th

Looping back. Alex is calling Joe. Thanks all.

From: Edstrom, Brittanie [mailto:BEdstrom@hunton.com]
Sent: Friday, September 01, 2017 10:56 AM
To: Kime, Robin <Kime.Robin@epa.gov>
Cc: Hutchins, Eric M. <ehutchins@hunton.com>; Stanko, Joseph <jstanko@hunton.com>
Subject: FW: Ozone Meeting Confirmation on September 6th

Good Morning Robin,

Per your conversation with Eric Hutchins, I am forwarding this email along to confirm the meeting for Wednesday September 6th at 3:00pm. Please let me know if this time is still available. Also, I have attached Joe Stanko's email with Samantha Dravis, which referenced you and Alex Dominguez, in regards to setting up the meeting for your reference.

Regards,

Brittanie Edstrom
Federal Affairs Adm Assistant
bedstrom@hunton.com
p202.955.1523

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037

hunton.com

From: Edstrom, Brittanie
Sent: Thursday, August 31, 2017 3:45 PM
To: 'Kime.Robin@epa.gov'
Cc: Stanko, Joseph
Subject: Ozone Meeting Confirmation on September 6th

Hello Robin,

I am reaching out to you on behalf of Joe Stanko regarding the request for a trade association meeting on Ozone. We would like to confirm the meeting on Wednesday, September 6th at 3:00pm. Please let us know the contact information for who will accompany us post-security clearance. We can provide a list of attendees in advance.

Regards,

Brittanie Edstrom
Federal Affairs Adm Assistant
bedstrom@hunton.com
p202.955.1523

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037

hunton.com

VanNess Feldman LLP

1050 Thomas Jefferson Street, NW
Seventh Floor
Washington, DC 20007
(202) 298-1800 Phone
(202) 338-2416 Fax

September 18, 2015

Administrator Gina McCarthy
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

VIA EMAIL AND FIRST-CLASS MAIL

Dear Administrator McCarthy,

Attached is a petition for administrative reconsideration of the final rule, entitled "*Protection of Stratospheric Ozone: Change of Listing Status for Certain Substitutes Under the Significant New Alternatives Policy Program,*" published at 80 Fed. Reg. 42,870 (July 20, 2015), filed on behalf of Compsys, Inc. and Structural Composites, Inc.

Please do not hesitate to contact me at 202-298-1991 or alh@vnf.com with any questions you may have. Scott M. Lewit, President of Compsys, Inc. and Structural Composites, Inc. may be contacted at 321-252-4566 or slewit@aol.com.

Sincerely,

Andrea Hudson Campbell
Attorney for Compsys, Inc. and
Structural Composites, Inc.

CC: Drusilla Hufford, U.S. EPA, Director, Stratospheric Protection Division, via email
Margaret Sheppard, U.S. EPA, Stratospheric Protection Division, via email
Cindy Newberg, U.S. EPA, Branch Chief, AERB, Office of Air and Radiation, via email
Rebecca Von Dem Hagen, U.S. EPA, Stratospheric Protection Division, via email

September 18, 2015

Administrator Gina McCarthy
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

VIA EMAIL AND FIRST-CLASS MAIL

Dear Administrator McCarthy:

This is a petition for administration reconsideration submitted under section 307(d)(7)(B) of the Clean Air Act (CAA). Structural Composites, Inc. is a research and development company focused on engineering and development of composites for marine, military, and other commercial applications. Structural Composites holds a controlling interest in Compsys, Inc., the manufacturer of preform composites under the brand name Prisma. Prisma products are used in a wide variety of marine applications, as well as in commercial refrigerated trucks and other transportation uses. Our composite preforming production process and products require the use of HFC-134a as a foam-blowing agent. Structural Composites and Compsys request that you reconsider certain aspects of the final rule issued at 80 Fed. Reg. 42,870 (July 20, 2015), entitled "*Protection of Stratospheric Ozone: Change of Listing Status for Certain Substitutes Under the Significant New Alternatives Policy Program.*"

In the final Significant New Alternatives Policy (SNAP) rule, EPA established various deadlines after which HFC-134a cannot be used, depending on the end-use of the product. EPA did not take final action regarding the use of HFC-134a for use in Rigid Polyurethane (PU) Spray Foam. However, for Rigid Polyurethane Marine Flotation Foam, use of HFC-134a as a blowing agent is deemed "unacceptable" as of January 1, 2020. EPA also did not prohibit the importation of products containing closed cell foams for which HFC-134a was the foam blowing agent.

Structural Composites and Compsys request that EPA clarify the scope of the Rigid Polyurethane Spray Foam end-use. Compsys' product is unique and has characteristics of both "rigid polyurethane spray foam" and "marine flotation foam." Therefore, the applicability of the rule to our product is not clear. Thus, Compsys requests that EPA clarify that the "rigid polyurethane spray foam" end-use includes composite preforming uses, such as Prisma. Compsys further requests that EPA clarify that the designation of HFC-134a as "unacceptable" for use as a Rigid Polyurethane Marine Flotation Foam blowing agent, effective January 1, 2020, does not apply to use of HFC-134a for *structural* marine foam uses—including composite preforming. Structural Composites and Compsys also request that EPA allow the continued use of HFC-134a in composite preforming, without a deadline, until substitutes are identified for this very narrow end-use that has overall greenhouse gas (GHG) reduction benefits when used in marine and on-road transportation applications.

Compsys and Structural Composites also request that EPA reconsider the decision to allow the importation of closed-cell foam products for which HFC-134a was the blowing agent. Allowing such products to be imported while prohibiting the production of items using an almost-identical process in the U.S. will create a massive competitive disadvantage to American companies. By pushing production outside the U.S., the rule would have the unintended effect of increasing the use and emissions of HFC-134a.

I. EPA Must Clarify the Applicability of the Final Rule and Provide a Clear Exemption for HFC-134a Foam Blowing Used in Composite Preforming.

In the final rule, EPA states "blowing agents are approved on an end use basis," and that "the SNAP program considers the following end uses: [...] Rigid PU (spray, commercial refrigeration, and sandwich panels) includes buoyancy foams, insulation for roofing, wall, pipes, metal doors, vending machines, coolers, and refrigerated transport vehicles."[1] EPA then states that the agency is creating narrowed use limits for HFC-134a and blends thereof, as well as other substances, for all foam blowing end-uses except rigid PU spray foam.[2] EPA based the decision to take no final action on a status change for rigid PU spray foam blowing agents because "some of the lower-GWP, flammable alternatives that are listed as acceptable in other foam blowing end-uses, such as C3-C6 hydrocarbons and methylal, are not acceptable for use in rigid PU spray foam," largely due to the flammability of the alternatives, the method of application, and place of use. EPA further states that there are "three main types of rigid PU spray foam: High-pressure two-part spray foam systems, low-pressure two-part spray foam systems, and one-component foam sealants."[3]

EPA also recognized in the final rule the United States Coast Guard requirements that all monohull recreational boats less than 20 feet in length have adequate flotation foam to keep any portion of the boat above the surface of the water when submerged in calm, fresh water for at least 18 hours and when loaded with specified weights.[4] However, EPA did not define "marine flotation foam" anywhere in the final rule, aside from listing "this use separately from spray foam due to the differences in the manner in which the foam is dispensed which make this use more similar to appliance foam and commercial refrigeration foam than spray foam." EPA further stated that the agency's "understanding is that flotation foam is typically injected rather than sprayed."

Compsys submitted comments to EPA during the comment period, as well as after the close of the comment period, explaining that Compsys' Prisma product is neither a typical "spray foam" or "marine flotation foam."[5] Rather, as also detailed in our comments, our unique product has characteristics of both of these end-uses. Prisma products use high-quality fiberglass knit fabrics, 2 PCF flotation grade polyurethane foam, and a polyester veil. The fiberglass knit fabric is placed inside a mold in order to create pre-formed, standard shape and size components. The fiberglass knit fabric also can be shaped directly to form the frame of the hull, hatch, or other component of a boat to create custom products. The polyurethane foam is then sprayed or injected into the mold or frame, and closed out with a patented polyester tie veil interface. Once cured, this patented process creates an extremely strong interface between the fiberglass and foam. It also helps support dynamic loads, resists cracking and wear, and allows the product to be extremely lightweight.

Prisma foam products do not offer only flotation. The patented polyester tie veil interface creates such a strong product that it can be used for structural boat components such as stringers, bulkheads, hull and deck stiffeners, beams, fuel tank supports, structural members, long-span stiffeners, corner

---

[1] 80 Fed. Reg at 42,923.
[2] *Id.*
[3] *Id.* at 42,925.
[4] 33 C.F.R. §§ 183.101, 183.105.
[5] *See* Structural Composites Comments, EPA Docket ID No. EPA-HQ-OAR-2014-0198-0172 (Oct. 20, 2014); *see also* ACMA Comments, EPA Docket ID No. EPA-HQ-OAR-2014-0198-0132 (Oct. 20, 2014), and Structural Composites letters to EPA Docket dated April 13, 2015, May 7, 2015, and June 2, 2015.

stiffeners, hull side-to-bottom strengthening, hatch and swim platform reinforcement, insulated compartments and fish boxes. While these components do provide flotation benefits, they also form the structure of the boat. Compsys currently supplies or licenses our technology to more than 30 OEM boat manufacturers. We also have worked with the United States Department of Defense and the United States Navy on applying our technology to military applications. This joint research has found great benefits to use of Prisma in naval applications, including increased fuel efficiency, performance, and payload while reducing overall ship weight. Overall, the characteristics of Prisma offer major environmental benefits, including improved fuel efficiency and reduced GHG emissions. A more detailed discussion of the environmental benefits of our product is provided below.

Compsys and Structural Composites have researched, and continue to investigate, whether alternatives to HFC-134a can be used in our process. We previously phased out HCFC-22 and replaced that substance with HFC-134a. However, we have not yet identified a substitute for HFC-134a. We continue to examine alternatives but urge EPA to continue to allow this end-use, without restriction, until a viable alternative is identified. In addition, EPA vastly underestimated the costs of compliance with the final rule for our industry. We understand that EPA believes it is bound to consider only the difference in costs between a substance and the alternative, and not the costs of manufacturing facility upgrades or changes. However, the compliance costs to our industry are infinite because no alternative currently exists.

EPA did not acknowledge in the final rule that Compsys' product differs greatly from what EPA considered as part of the marine flotation foam end-use, which is used only to provide adequate flotation, or that Compsys' process is not a typical rigid polyurethane spray foam process. Nor did EPA consider the overall environmental and GHG lifetime benefits associated with a lightweight and extremely durable product that can be adapted to a wide variety of transportation, marine, and military uses. Finally, EPA did not take into consideration the fact that no alternative is currently or imminently available for our composite preforming process. Therefore, Compsys urges EPA to reconsider the final rule and clarify that composite preforming using polyurethane spray foam and the patented Prisma process should be classified as a HFC 134a foam blowing end-use for which there are no narrowed use limits or restrictions.

II. Environmental Considerations Support an Exemption for HFC-134a Used as a Foam Blowing Agent in Composite Preforming.

a. Composite Preforming Offers Significant Lifetime GHG Reductions and Improvements in Fuel Economy when Used in Marine and Transportation Applications.

As also discussed in detail in our comments on the proposed rule, Compsys' Prisma product results in significant lifetime GHG reductions and offers measureable improvements in vehicle and engine fuel efficiency. Our research, including that conducted jointly with the Department of Defense and U.S. Navy, indicates that Prisma products can achieve a 40-60% overall reduction in boat weight compared to standard fiberglass construction, without sacrificing hull strength. Lighter-weight boats also achieve better fuel economy—reducing U.S. petroleum consumption, GHG emissions, and emissions of other pollutants of concern. Compsys and Structural Composites found that boats built using our technology achieved up to a 40% improvement in fuel efficiency.

Prisma also has great potential for use in the on-road transportation sector, particularly in refrigerated trailers. Prisma is at least 255% more thermally efficient that current trailer fabrications, leading to

lower usage of on-board cooling technologies, which in turn means lower overall fuel consumption. Because Prisma is so lightweight yet structurally strong, it can be used as structural components in both refrigerated and standard trailers. Lighter-weight trailers also contribute greatly to overall fuel savings, reduced GHG emissions, and lower emissions of other air pollutants. Prisma also can be used to create structural components for flat-bed trailers, truck bodies, buses, recreational vehicles, and other types of vehicles. We provided a detailed discussion of the overall lifetime GHG savings in our comments on the proposed rule.[6]

EPA is currently working on a rule to establish more stringent GHG emission standards for heavy-duty trucks and trailers. Our technology has the potential to offer significant overall GHG reductions and fuel savings for this transportation sector. We therefore urge EPA to carefully consider the relationship between the SNAP program and the heavy-duty GHG rule. If the SNAP rule limits or prohibits the use of HFC-134a as a foam blowing agent for our process, EPA will have eliminated a potential avenue for achieving even greater GHG reductions from the on-road transportation sector.

b. Very Little HFC-134a is Released into the Atmosphere in the Composite Preforming Process.

Our preliminary research indicates that approximately one-tenth of the HFC-134a used in our composite preforming process is released into the atmosphere. Our polyurethane foam is sprayed into a mold that is completely encapsulated in a composite coating. Because of the size of the HFC-134a molecule, it cannot pass through the composite coating. Thus, any HFC-134a that reaches the atmosphere occurs during the spray process. Once the foam is enclosed and fully encapsulated, any HFC-134a retained in the foam will be permanently enclosed.

As a result, the GHG emissions and overall global warming potential associated with HFC-134a use in composite preforming are extremely low. Moreover, such GHG emissions are non-recurring and are negligible in comparison to the overall GHG reductions that will be achieved by improving boat and vehicle fuel economy. Our calculations indicate that use of Prisma preform technology in refrigerated trailers can reduce GHG emissions by approximately 25 tons of CO_2-equivalent per year and 650,000 lbs. of CO_2-equivalent over the useful life of the trailer. Also associated with use of lightweight Prisma products would be hundreds of thousands of gallons of fuel savings.[7]

Due to the great potential for longer-term GHG reductions at the cost of de minimis emissions of HFC-134a from the foam blowing process, Compsys and Structural Composites urge EPA to continue to allow unrestricted use of HFC-134a as a blowing agent for composite preforming.

III. EPA Must Reconsider Allowing the Importation of Products Produced with HFC-134a as the Foam Blowing Agent if Similar Uses Will Be Prohibited Within the U.S.

In the proposed rule, EPA proposed to prohibit the importation of products made with foam if the foam blowing agent for that product and end use was unacceptable for that end-use in the United States. However, EPA changed course in the final rule and will continue to allow the importation of foam products produced with blowing agents that are or will be unacceptable for that end-use in the U.S.,

[6] *See* Structural Composites Comments, EPA Docket ID No. EPA-HQ-OAR-2014-0198-0172 (Oct. 20, 2014).
[7] *See id.*

even if the closed-cell foam contains blowing agents that are unacceptable in the U.S. Compsys and Structural Composites strongly urge EPA to reconsider this approach.

As EPA well knows, the effect of a substance with global warming potential is the same regardless of where that molecule is released into the atmosphere. Any reductions in GHG emissions that EPA expects to achieve under the SNAP rule may easily be offset by companies moving production of foam blowing operations outside of the U.S. By continuing to allow importation of foam products produced with blowing agents deemed unacceptable in the U.S., the rule may actually lead to the unintended consequence of *increased* overall GHG emissions—albeit outside of the U.S.

Even leaving aside environmental considerations, EPA's decision to continue to allow imported foam products while prohibiting the same manufacturing processes within the U.S. has massive financial and competitive consequences for the foam blowing industry. Companies with operations located solely within the U.S.—including small businesses such as Compsys and Structural Composites—that contribute to the growth and prosperity of the U.S. economy will be put out of business. Multi-national companies or those that have chosen to site manufacturing in other nations with less-stringent environmental standards will prosper. If EPA retains the exemption for imported products, then EPA must reconsider the applicability of the final SNAP rule to products manufactured within the U.S. to avoid bankrupting successful, innovative American small business.

* * * * *

For all of the foregoing reasons, Compsys and Structural Composites respectfully request that EPA reconsider certain aspects of the final SNAP rule, entitled "*Protection of Stratospheric Ozone: Change of Listing Status for Certain Substitutes Under the Significant New Alternatives Policy Program*" 80 Fed. Reg. 42,870 (July 20, 2015). We look forward to further discussions with EPA on this matter.

Please do not hesitate to contact me at 321-252-4566 or slewit@aol.com with any questions you may have.

Sincerely,

Scott Lewit /AHC

Scott M. Lewit
President
Structural Composites, Inc. and Compsys, Inc.

CC: Drusilla Hufford, U.S. EPA, Director, Stratospheric Protection Division, via email
Margaret Sheppard, U.S. EPA, Stratospheric Protection Division, via email
Cindy Newberg, U.S. EPA, Branch Chief, AERB, Office of Air and Radiation, via email
Rebecca Von Dem Hagen, U.S. EPA, Stratospheric Protection Division, via email

VanNess Feldman LLP

1050 Thomas Jefferson Street, NW
Seventh Floor
Washington, DC 20007
(202) 298-1800 Phone
(202) 338-2416 Fax

Andrea Hudson Campbell
202-298-1991
alh@vnf.com

January 17, 2017

SUBJECT TO FOIA EXEMPTION 4
CONTAINS CONFIDENTIAL BUSINESS INFORMATION

Jan Tierney
U.S. Environmental Protection Agency
USEPA Headquarters
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 2344A
Washington, DC 20460

Dear Ms. Tierney:

Below are Compsys/Structural Composites' responses to the questions contained in your email dated January 9, 2017. We appreciate the opportunity to provide this follow-up information and would be pleased to further discuss any of the answers below.

Q1. Is the Compsys product currently being used in trailers or is that use still in development?

Compsys' product is currently being used in both trailers and in truck bodies. Use of Compsys' product in trailers and truck bodies began in June 2015. We estimate that 2 trailers and 36 truck bodies have been produced to date containing Prisma components. Limited early production truck bodies are being sold to key customers for evaluation. Prisma has been qualified for use in semi-trailer applications and early production is now starting. Compsys currently provides Prisma components to Wabash. Plans are in motion for scale-up at Wabash with the projection to transition the entire van and truck body lines (60,000 annual build rate).

As also noted below, Compsys is in discussions with a global automotive OEM and large US DOD prime with regard to deployment of our technology in those sectors. Testing to determine Prisma's qualification for use in infrastructure projects is progressing; a state DOT report is expected shortly reporting on qualification testing for new bridge construction.

Q2. To the extent it is being developed/used for trailers, is it used solely for refrigerated transport trailers or is it being used for other types of trailers?

Our product is currently used in both refrigerated and "dry" (non-refrigerated) transport trailers, as well as in refrigerated and dry truck bodies. Currently, the use of Prisma is evenly split between refrigerated and dry truck bodies. The trailers that have been produced to date are prototypes and test articles; all have been refrigerated.

As we have explained, use of Prisma in refrigerated trailers and truck bodies provides superior insulation, reducing the amount of cold air that must be generated and circulated within the trailer in order to maintain the necessary temperature. Prisma also is extremely light-weight, compared to traditional wood, metal, or other composite materials, resulting in significant reductions in the amount of fuel used during transport of goods. For both refrigerated and dry trailers, Prisma offers weight reduction, ease of maintenance, and elimination of corrosion, which extends the trailer life cycle. We are projecting a doubling of product life cycle through the elimination of corrosion based on composites long history of in-service durability.

Q3. What kinds of components are produced for use in refrigerated trailers?

Compsys produces components that form the primary structure of the trailer or truck body, whether that trailer or truck body is refrigerated or dry. Prisma components are used to create the floor, chassis, nose wall, roof, and sidewalls, replacing components that were previously made of wood, metal, or other types of composites.

Q4. How does the wall of a trailer, for example, differ from the wall of a trailer that does not use Prisma?

Prisma allows for the construction of a wall that is 100% composite. Prisma elements are co-molded with the composite inner and outer skin into a component meeting the exact size and specifications of the trailer wall. Metal ribs and other metal materials are completely eliminated. Prisma can be used to create the entire sidewall of a trailer, creating a seamless construction.

In contrast, traditional trailer walls constructed of other materials use a metal frame, metal outer skin and a thermoplastic composite inner skin. The metal-framed components can be first installed into the truck, with the foam injected into the cavities in the nearly-complete truck body, or individual metal-framed components can placed into massive foaming jigs and later installed into the truck body. The panels or other components are typically fastened together using metal rivets. The material, systems and the nature of the large foam show results in a panel that has less insulation quality and more weight than the Prisma panel.

Q5. Do you know whether there are other trailers produced using composites that do not use Prisma's process? If you are aware of such use, do you know whether insulation foam is also used if the trailer is used for refrigerated transport?

Other manufacturers use the processes described above, where metal-framed components are injected with foam either in place in the truck body or trailer, or where metal-framed components are individually injected with foam and then assembled into the complete truck body or trailer. We are not aware of any other major manufacturer that is producing all-composite walls and other components the way we are.

As we have previously explained, our use of a fiberglass-reinforced outer fabric is unique and requires the use of foam with different properties from the foams used in metal-framed components. The fiberglass fabric is porous, unlike metal or thermoplastic materials. Therefore, our process must use

a foam that will not permeate the fabric; metal-framed components do not have the same concern with permeation.

Q6. Is the Compsys product currently being used in uses other than boats and trailers? If so, what uses?

Prisma beams are used in composite applications, such as theme park rides, chemical tanks, industrial composites and for the repair and restoration of structure]. These beams and other standard-sized components are available for purchase through an independent distributer and could be used in used in areas that we are not aware of.

Q7. Is it currently being developed for use in other uses? If so, what uses and what is the projection on when it might be actively used?

Compsys/Structural Composites are very active in developing products for use in infrastructure applications, in particular Composite Bridge Decking. The Oklahoma Department of Transportation (DOT) has recently completed extensive testing on a new version of our decking that is targeted to new bridge construction (vs. retrofit). We are also developing applications in the following areas:

- Infrastructure uses—deployment projected prior to 2020.
- Automotive—current project moving from planning to development, expected in 2019.
- Building Construction—targeting Commercial Buildings in the 2020-2022 timeframe.
- Alternative Energy—Compsys' products are already used in some small applications. Further development and deployment is expected in wind energy applications.
- Corrosion Market (chemical tanks)—Compsys' products are currently used in small applications for oil and chemical holding tanks; additional applications are planned and expected in the next few years.
- DOD—Compsys has partnered with the U.S. Department of Defense on a variety of projects using our product. This partnership will be significantly expanding in 2017. Among the existing DOD projects are the following:
    - U.S. Navy, Defense Advanced Research Projects Agency (DARPA) MARITECH Program to develop a composite ship superstructure system; a joint project between Structural Composites, Ingalls Shipbuilding, American Bureau of Shipping, and Naval Sea Systems Command.
    - U.S. Navy Small Business Innovative Research (SBIR) Phase I Program: Development of a New Composite Manufacturing Process for Special Forces Maritime Craft.
    - U.S. Navy SBIR Phase I Program: Energy Absorptive Resin Materials for Undersea Structure Radiated Noise Reduction.
    - U.S. Navy SBIR Phase II Program: Study of Fire Performance of Composite Materials in a Submarine Environment.
    - U.S. Navy SBIR Phase I Program: Effects of Fiber Reinforced Plastic Composites in Submarines.
    - US Navy SBIR Phase I, II, III- Advanced Combatant Craft for Increased Affordability (Structural Composites, Inc).
    - 2016 Award Rapid Innovation fund- SBIR Phase III- Advanced Combatant Craft for increased affordability. 2.7M, 2 year effort- Awarded Sept 2016 (Structural Composites, Inc).

Q8. Is foam currently used in those other uses? If so, how is it applied?

Polyurethane foam is currently used in some of these end-uses, but not in all. In those applications where foam is currently used, the process differs from Compsys' product. As explained above, these applications require a wood or metal frame, and the foam is then injected into the cavities formed by that framing. Our product eliminates the wood or metal framing requirement. Our understanding of the use of foam in the applications currently under development by Compsys/Structural Composites is as follows:

- Infrastructure—foam is not currently used. Composite materials would replace steel and concrete components.
- Automotive—Foam is not currently used the targeted applications. Prisma/composite materials would replace steel and aluminum components.
- Building Construction—Foam or other material is currently used as insulation and is sprayed or injected into wall or ceiling cavities. Prisma would replace the metal or wood framing as well as the spray-foam or other types of insulation with a single component that forms both the structure of the building and provides insulation and noise reduction.
- Alternative Energy—Our targeted applications currently use PVC foam and Balsa core. Polyurethane foam is not widely used.
- Corrosion Market/chemical holding tanks –Polyurethane foam is not generally used in these applications. These tanks are typically constructed of steel, fiberglass, or a combination of those materials.
- DOD—The U.S. Department of Defense currently has very limited uses of polyurethane foam. Our product would replace steel, fiberglass, and other traditional materials in DOD applications.

Q9. Can you better explain how the product is used as a structural component in the end uses for which it is being used? In other words, what part of the structure is being replaced and what material is being replaced (e.g., wood, fiberglass etc) in building boats, in manufacturing refrigerated trailers, and in other uses?

In boats, Prisma forms the skeleton of the boat. Prisma replaces wood, metal, or other heavier and more expensive composite components. In trailers and truck bodies, Prisma is used to form the floor and underlying chassis structure, as well as the roof and walls. These structures were traditionally constructed from wood, metal, fiberglass, or other composites.

To help illustrate how and where Prisma products are used, we have provided the following images. Note that each of the boats pictured is greater than 20 feet in length, meaning that there are no specific marine flotation foam requirements under current United States Coast Guard regulations. As you can see, the Prisma composite foam components are used to form the structure of these boats and is not injected into cavities framed by wood, metal, or fiberglass. The same is true for the use of Prisma components in truck bodies and trailers. Prisma forms the wall, roof, or floor of truck bodies and trailers and is not foam that is injected into the cavities framed by wood or metal structures.

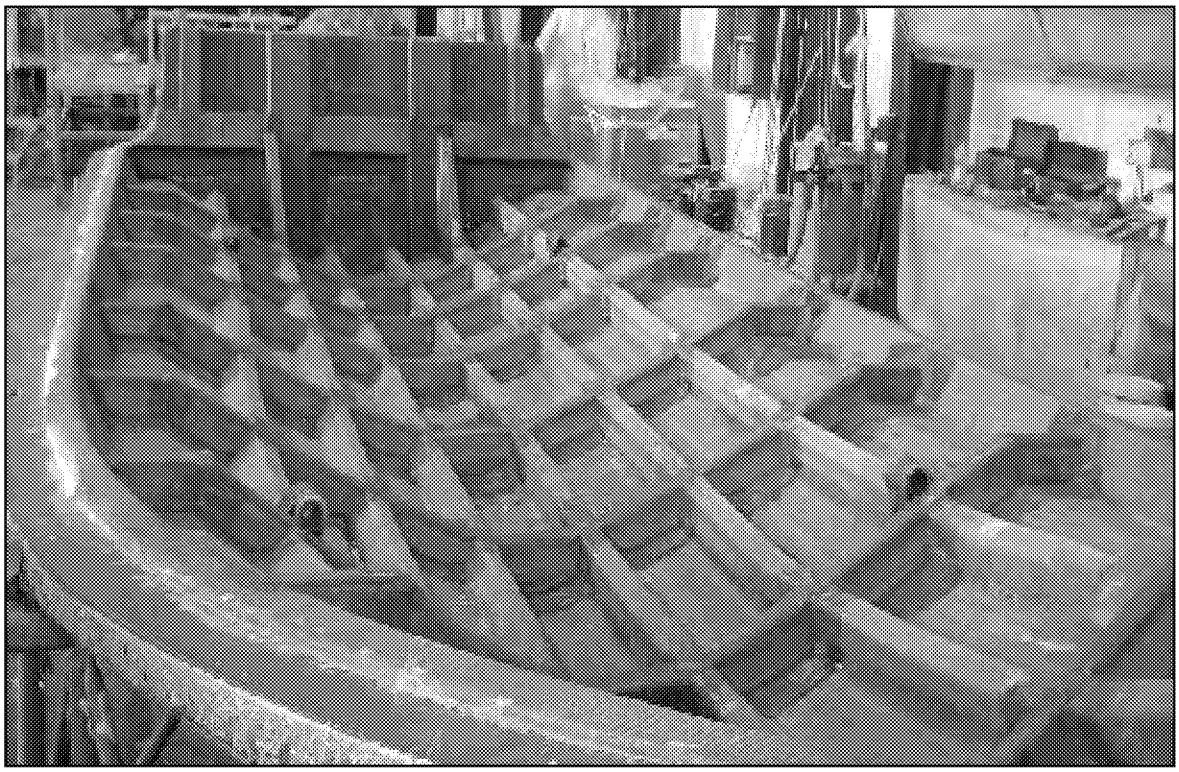


Figure 1. Advanced Design Lightweight Navy Combatant Craft Hull. All of the beams shown in this photo are made of Prisma. These beams replace traditional wooden or other composite framing in the hull.

Figure 2. Transom and Aft Stringer Structure for the Hydrasports 53, the world's Largest Outboard Powered Center Console. These components are Prisma (shown laminated).

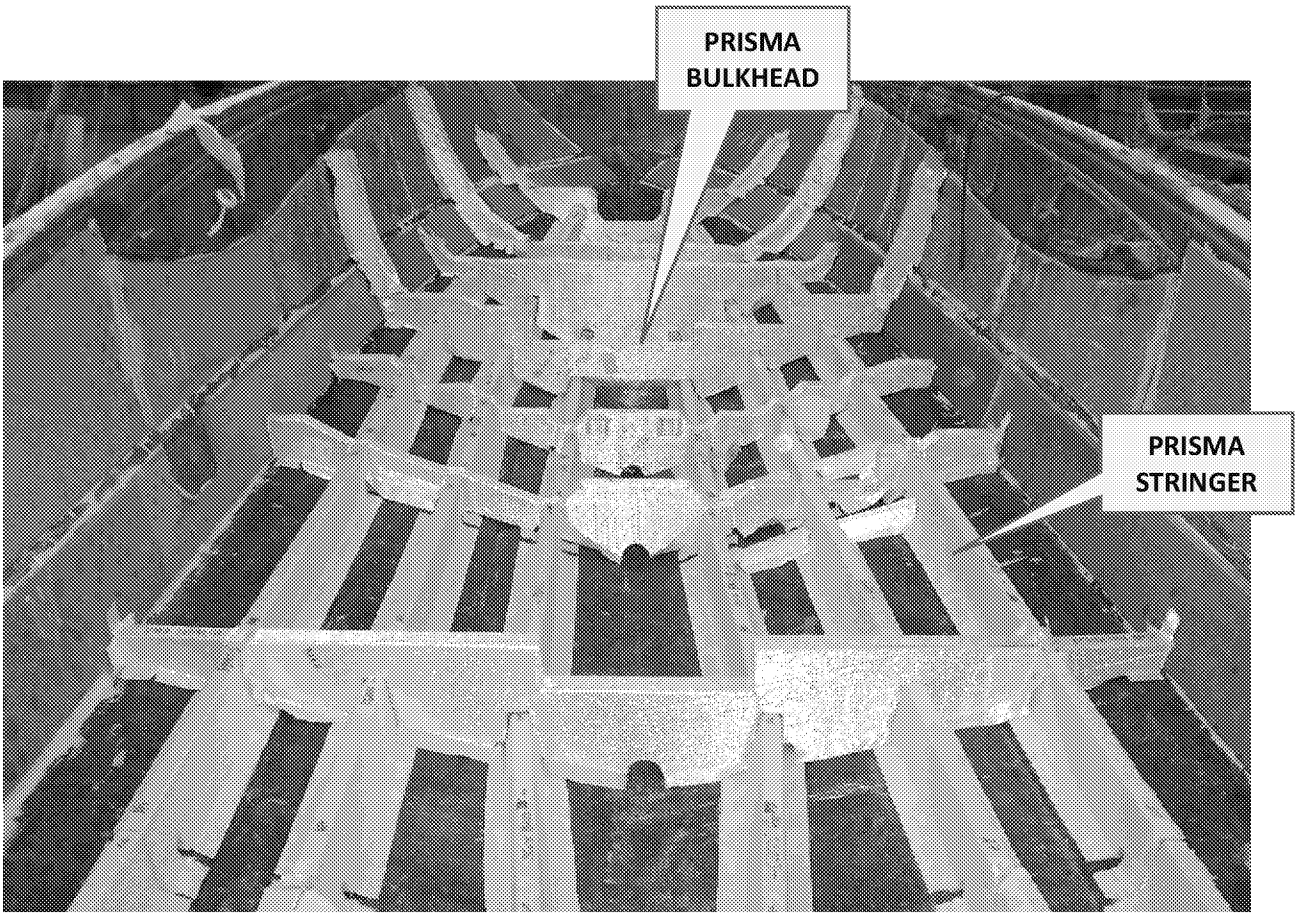


Figure 3. Power Yacht- Prisma System- Brunswick Boats. All of the stringers and bulkhead components shown are made of Prisma. Traditionally, these components would be made of wood, fiberglass, or metal.

SUBJECT TO FOIA EXEMPTION 4
CONTAINS CONFIDENTIAL BUSINESS INFORMATION

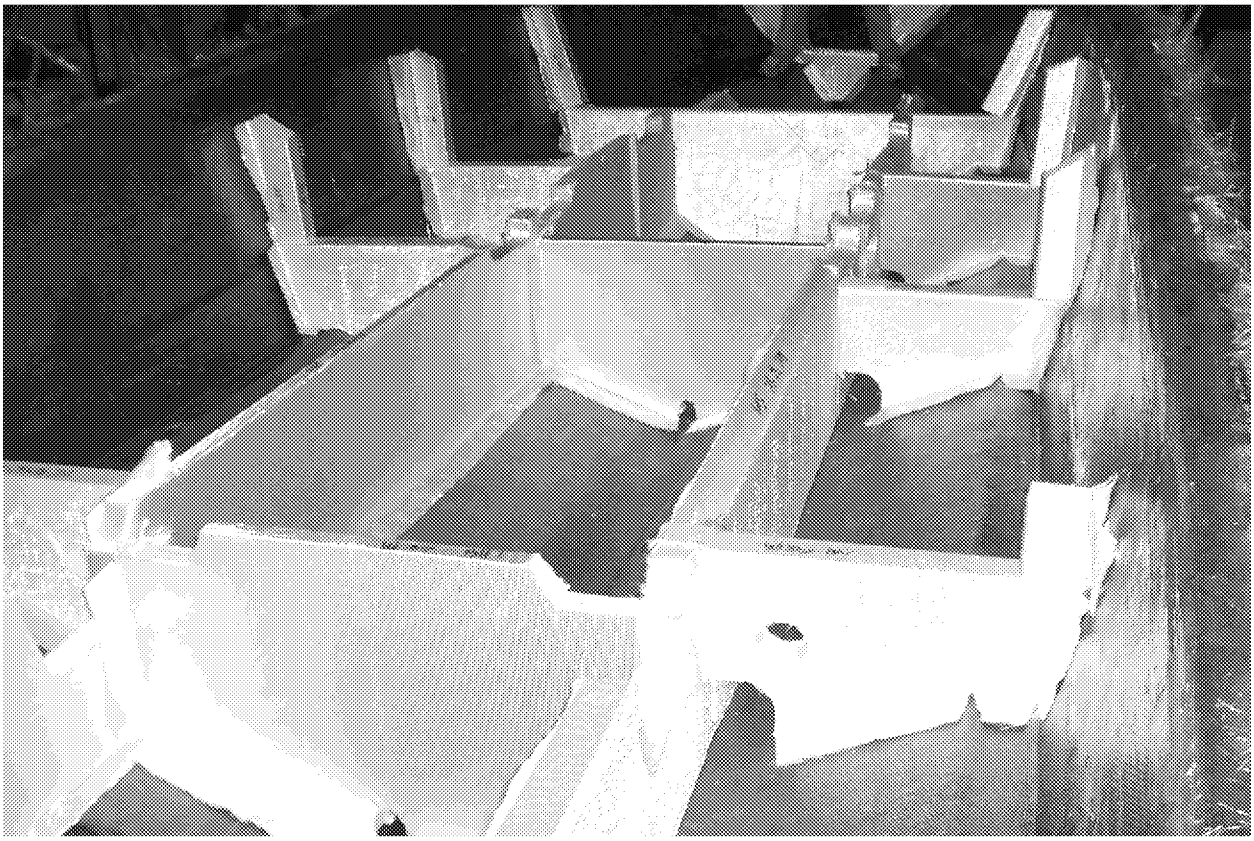


Figure 4., Large Boat Prisma System- Wellcraft. Again, the bulkhead and stringers shown are made of Prisma and replace wooden, fiberglass, or other materials.

Figure 5. Large Bulkhead Prisma- Grady White 336. Component is shown before installation into the hull of the boat.

In trailers, Prisma composites are replacing the entire floor chassis structure in both refrigerated and non-refrigerated trailers, as well as the wall and roof structures in refrigerated trailers.

Figure 6. 53 ft Composite Refrigerated Van--Wabash Prisma Construction

Figure 7. Coupler Plate Prisma Framed Floor- Qualification Testing at Wabash- Laminated Prisma Frames

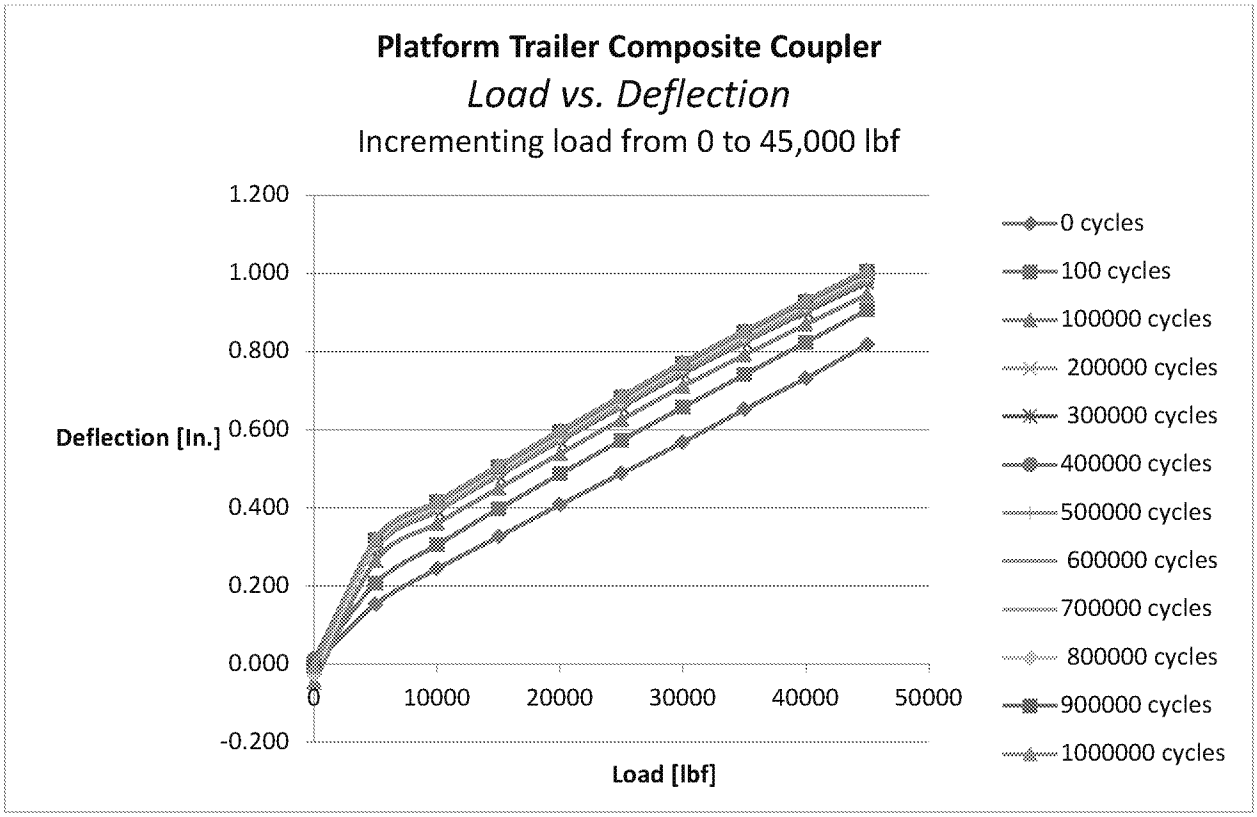


Figure 8. Test Data from Coupler Plate Test

Figure 9. Refrigerated Truck Body- Wabash Prisma Construction

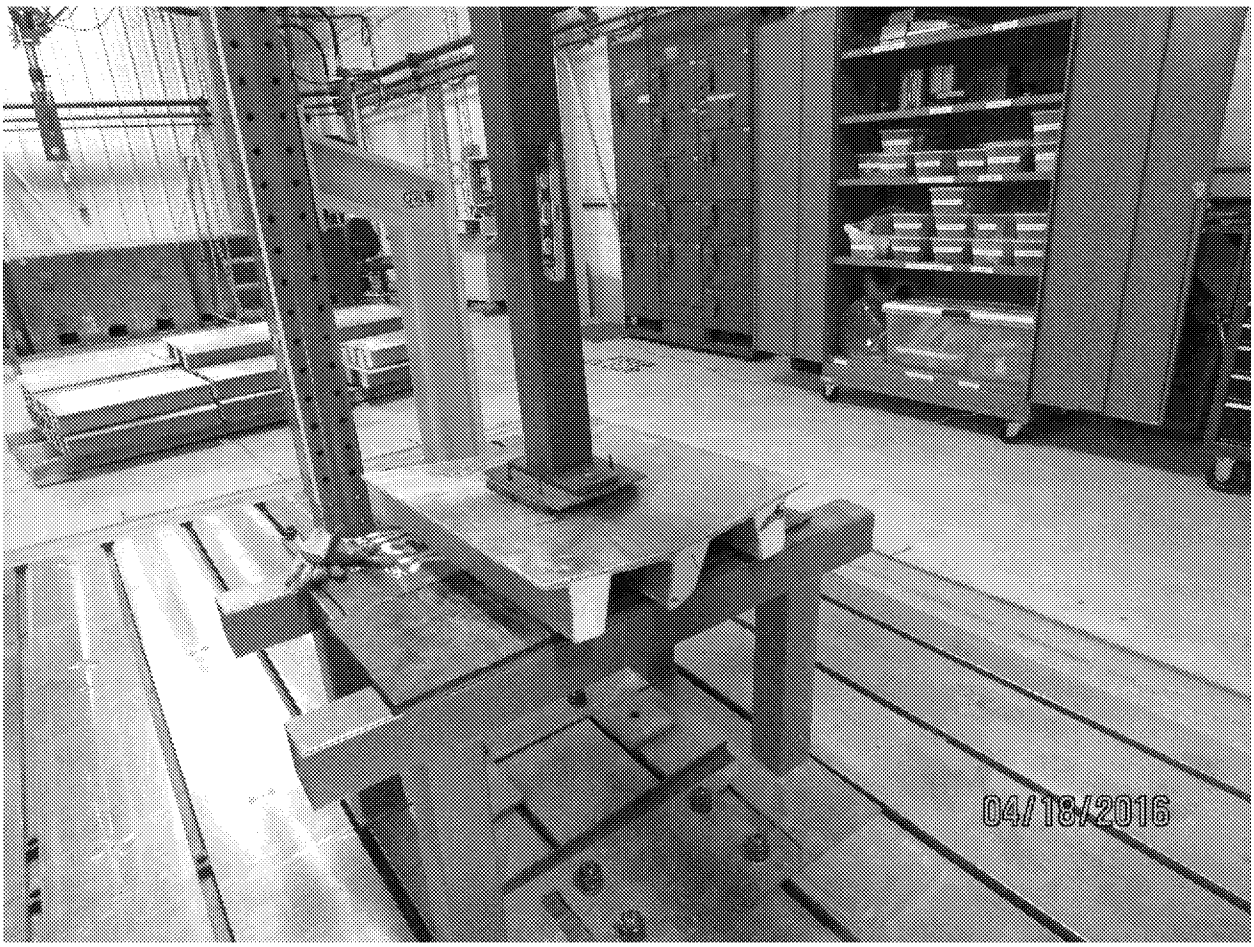


Figure 10. Crush Test- Wabash Prisma. Prisma met all expectations for crush testing and strength for use in Wabash truck bodies and trailers, replacing wood or metal components.

Figure 11. Track Testing to Qualify Technology- Truck Body

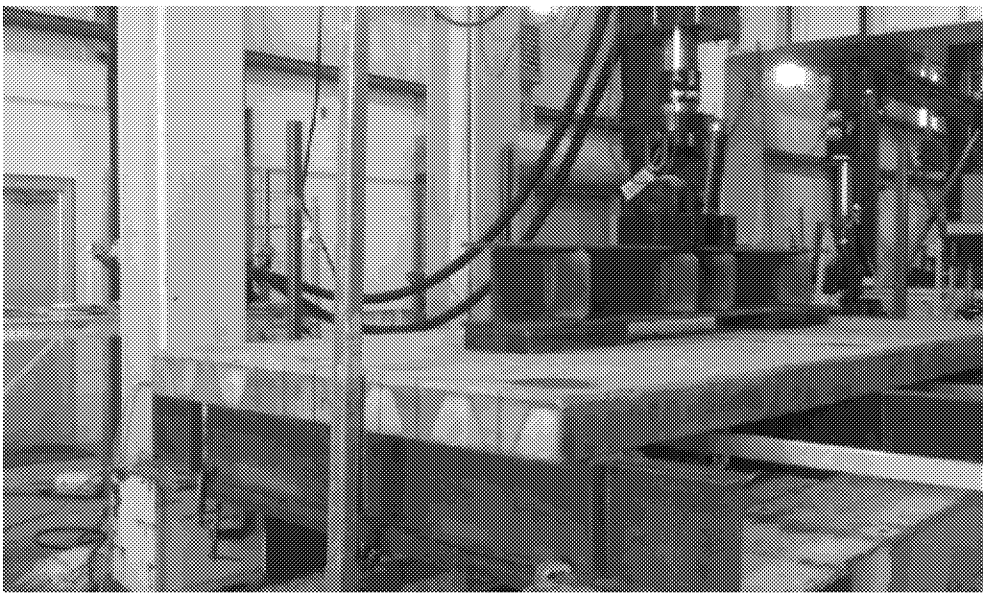


Figure 12. Composite Bridge Decking Undergoing Qualification Testing at Florida DOT

*****

I hope this letter is responsive to your questions and provides a better understanding of the Prisma products and the way in which these components are used in boats, truck bodies, and trailers, as well as the prospects for future applications of Prisma. Please let me know if you have additional questions or would like to further discuss any of the information provided above.

Sincerely,

Andrea Campbell

Andrea Hudson Campbell

SUBJECT TO FOIA EXEMPTION 4
CONTAINS CONFIDENTIAL BUSINESS INFORMATION

June 2, 2016

Chenise Farquharson
Stratospheric Protection Division
Office of Atmospheric Programs (Mail Code 6205T)
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, NW
Washington, DC 20460

ATTN: DOCKET ID NO. EPA-HQ-OAR-2015-0663

VIA ELECTRONIC FILING

Compsys and Structural Composites appreciate the opportunity to comment on EPA's proposed rule, *Protection of Stratospheric Ozone: Proposed New Listings of Substitutes; Changes of Listing Status; and Reinterpretation of Unacceptability of Closed Cell Foam Products under the Significant New Alternatives Policy Program; and Revision of Clean Air Act Section 608 Venting Prohibition for Propane*, published at 81 Fed. Reg. 22810 (April 18, 2016).

Structural Composites, Inc. is a research and development company focused on engineering and development of composites for marine, military, and other commercial applications. Structural Composites holds a controlling interest in Compsys, Inc., the manufacturer of preform composites under the brand name Prisma. Prisma products are used in a wide variety of marine applications, as well as in commercial refrigerated trucks and other transportation uses. Our composite preforming production process and products currently require the use of HFC-134a as a foam-blowing agent.

Compsys and Structural Composites recommend that EPA establish a specific application within the low-pressure two-component spray foam end use to reflect the unique attributes of Compsys' product with a temporary narrowed use limit that would permit the continued use of HFC-134a until January 1, 2025. In the alternative, Compsys and Structural Composites recommend that EPA create a new end-use within the rigid polyurethane spray foam category of end-uses in recognition of the differences between Compsys' process and other spray-foam end uses that EPA currently regulates and the current lack of available substitutes for HFC-134a. Compsys and Structural Composites recommend that EPA establish a deadline of January 1, 2025 for the phase-out of HFC-134a for use in spray foam composite preforming. Compsys and Structural Composites also recommend that EPA engage in a technical review for this new end-use no later than January 1, 2022 to determine whether a substitute has been identified for the spray foam composite preforming process.

Compsys and Structural Composites support EPA's proposal to prohibit the importation of closed-cell foam products produced with blowing agents which EPA has determined to be unacceptable for the same end use within the United States. Unlike other pollutants, substances with high global warming potential (GWP) have the same environmental effects regardless of where they are emitted. EPA's proposal will prevent manufacturers from relocating production to nations that do not have such stringent requirements, protecting both the environment and U.S.-based small businesses.

I. EPA Should Establish a Specific Application within the Low-Pressure Two-Component Spray Foam End-Use or a Create a New End-Use that Accommodates Products such as Prisma within the Rigid Polyurethane Spray Foam Category.

a. Compsys' Product Differs Significantly from the Applications and End-Uses EPA Has Identified within the Rigid Polyurethane Spray Foam Category.

Compsys' Prisma product is neither a typical rigid polyurethane "spray foam" or "marine flotation foam."[1] Rather, our unique product has characteristics of both of these end-uses. In the proposal, EPA describes as marine flotation foam as foams that "typically are injected into a cavity in the boat wall from a two-canister (A- and B-side) system under lower pressures... [to] provide structure as well as buoyancy."[2] EPA defines low-pressure two-component spray foam as products that are "pressurized to less than 250 psi during manufacturer, are sold in pressurized containers as two parts (*i.e.*, A-side and B-side), and are sprayed in the field for thermal insulation and air sealing of buildings. Low-pressure two-component spray foams are typically applied in situ relying upon a gaseous foam blowing agent that also serves as a propellant; pumps typically are not needed."[3] EPA noted in the proposal:

> "[I]t may be reasonable for several of the end-uses to be broken down further. Consistent with previous practice and as EPA is proposing in certain instances in this proposal, EPA could consider adopting temporary narrowed use limits for a specific application within an end-use if the Agency determined that substitutes would be available for all but that specific application as of a particular date. In that case, for applications in that end-use not covered by the narrowed use limit, the proposed rule would list the substitute as unacceptable as of that date. For the specific application at issue, the proposed rule could contain both a temporary narrowed use limit with an expiration data and a listing as unacceptable upon the expiration of the narrowed use limit. Any end user within the covered application would need to comply with the requirement to analyze and document that there are no other alternatives that are technically feasible for their specific end-use in order to use the substitute identified in the narrowed use limit."[4]

Compsys and Structural Composites support the creation of a specific application and narrowed end-use within the spray foam end-use that reflects the differences between Compsys' process and other regulated applications. Compsys' process differs in several significant ways from both marine flotation foam, regulated under the final rule issued at 80 Fed. Reg. 42870 (July 20, 2015) and from the low-pressure two-component spray foam products that EPA described in the current proposal. Compsys' process does involve two components (similar to the A-side and B-side canister approach) and is sprayed at low pressures. However, Compsys product is not sprayed or injected into boat cavities or walls, as is the case with true marine flotation foam. Nor is Prisma sold in pressurized containers for application *in situ* for thermal insulation or air

---

[1] *See* Structural Composites Comments, EPA Docket ID No. EPA-HQ-OAR-2014-0198-0172 (Oct. 20, 2014); *see also* ACMA Comments, EPA Docket ID No. EPA-HQ-OAR-2014-0198-0132 (Oct. 20, 2014), and Structural Composites letters to EPA Docket dated April 13, 2015, May 7, 2015, and June 2, 2015.
[2] 81 Fed. Reg. at 22868.
[3] *Id.* At 22869.
[4] *Id.* at 22824.

sealing. Rather, Compsys' Prisma product is produced entirely within Compsys' manufacturing facilities as structural components for boats, as well as for other uses.

Prisma products use high-quality fiberglass knit fabrics, 2 PCF flotation grade polyurethane foam, and a polyester veil. The fiberglass knit fabric is placed inside a mold in order to create pre-formed, standard shape and size components. The fiberglass knit fabric itself can be shaped to form the frame of the hull, hatch, or other component of a boat to create custom products. The polyurethane foam is then sprayed or injected into the mold or frame, and closed out with a patented polyester tie veil interface. Once cured, this patented process creates an extremely strong interface between the fiberglass and foam. It also helps support dynamic loads, resists cracking and wear, and allows the product to be extremely lightweight

Prisma foam products do not offer only flotation. The patented polyester tie veil interface creates such a strong product that it can be used for structural boat components such as stringers, bulkheads, hull and deck stiffeners, beams, fuel tank supports, structural members, long-span stiffeners, corner stiffeners, hull side-to-bottom strengthening, hatch and swim platform reinforcement, insulated compartments and fish boxes. While these components do provide flotation benefits, they also form the structure of the boat. Unlike the typical low-pressure two-component or marine flotation foams described by EPA, these components are produced as standard-sized, individual components that are then shipped to Compsys' customers to be installed into boats. Prisma components are not molded and formed in place. The rigid foam components take the place of components that would otherwise have been made of wood or other materials. Compsys currently supplies components or licenses our technology to more than 30 OEM boat manufacturers. Overall, the characteristics of Prisma offer major environmental benefits, including improved fuel efficiency and reduced GHG emissions.

b. *Compsys Faces Significant Technical Challenges in Identifying an Alternative and Meeting the Deadlines Proposed for Current Applications Identified within the Spray Foam Category of End-Uses.*

Compsys and Structural Composites have researched, and continue to investigate, whether alternatives to HFC-134a can be used in our process. We previously phased out HCFC-22 and replaced that substance with HFC-134a. Compsys and Structural Composites are working closely with BASF to identify an alternative to HFC-134a. However, we have not yet identified a substitute for HFC-134a. BASF has conducted several trials with an alternative that appeared to be promising, but the formulation provided by BASF failed to perform properly in Compsys' process. BASF has now turned to developing and evaluating another alternative, but the timing is uncertain.

Compsys and BASF are currently considering whether Solstice™ Liquid Blowing Agent (LBA) (1233zd(E), *trans*-1-chloro-3,3,3-trifluoroprop-1-ene) or Solstice™ Gaseous Blowing Agent (GBA) (HFO-1234ze) could be adapted to Compsys' process. EPA identified these as the likely substances to which high-pressure two-component spray foam and low-pressure two-component spray foam would transition after the phase-out of HFC-134a. To date, the GBA causes the resin used in Compsys' process to have a very short shelf life and initial trials at BASF with small-scale parts have not been successful. Likewise, the LBA has a liquid phase that causes

Compsys' foam to saturate the reinforcing fabric before it expands. This allows the foam to expand into the fabric, deforming the part and making it unusable.

These trials have taken nearly a year, to date, and have been continually delayed by technical challenges on BASF's part. Compsys initially expected to begin larger-scale trials in late 2015, but this timing has been delayed numerous times by the lack of availability of an alternative formulation that can perform as required even for small components.

Once BASF develops a potential alternative, then Compsys will have to begin its evaluations of how the formula performs. This involves several different trials creating parts of different sizes. The effect of ambient temperatures on the foam-blowing process also will be evaluated. Cool weather testing must be performed, which can only be done at certain times of year given Compsys and Structural Composites' location in Florida. If the BASF formulation meets initial performance expectations, then Compsys will have to evaluate structural and physical integrity of the product, as well as its insulating and flotation properties. For marine uses, the product also must be certified by the U.S. Coast Guard as meeting the applicable marine flotation foam requirements. Compsys also will have to conduct a serious of customer trials for each of the company's more than 20 direct-supply accounts in order to ensure that the new product meets Compsys' customers' needs. Compsys would then have to replace any components used in its manufacturing process that are not compatible with the new alternative.

At minimum, this process will take between 24 and 36 months from the time a valid alternative is identified and initial trials are successful. If the new alternative fails at any time within that period of time, then the process will have to start again from the beginning. At the current time, it is nearly impossible to predict how quickly Compsys will be able to implement an alternative foam blowing agent. Compsys and Structural Composites have little to no control over the pace at which BASF develops an alternative for this process. Although the companies are committed to expeditiously implementing an alternative, Compsys cannot speed up the pace of the development of that alternative. Nor can Compsys accelerate the pace of its product trials without potentially compromising product performance and customer expectations.

Compsys generally agrees with the economic impact of transitioning to an alternative, as outlined in EPA's "Economic Impact Screening Analysis for Regulatory Changes to the Listing Status of High-GWP Alternatives used in Refrigeration and Air Conditioning, Foams, and Fire Suppression." In less than a year since the July 20, 2015 final rule, Compsys has spent approximately $75,000 on efforts to identify an alternative. Once the trial phase begins, costs will increase dramatically. If alternatives fail and several rounds of trials are required, Compsys' costs could easily reach $500,000 to $1 million. For a small business, these costs will be extremely burdensome, particularly if Compsys is forced to phase out the use of HFC-134a before an adequate substitute has been identified for use in Compsys' production process.

Therefore, Compsys recommends that EPA establish a new, temporary narrowed use limit within the low-pressure two-component spray foam end use, or within the larger spray foam category of uses, for the spray foam composite preforming process with a deadline of January 1, 2025 for the phase-out of HFC-134a. As we have explained, Compsys is committed to transitioning to an alternative foam blowing agent. Understanding EPA's concerns about the environmental benefits of a widespread transition away from HFC-134a, Compsys would be willing to engage in a technical review with EPA no later than January 1, 2022 to determine if an

alternative has been identified for use in Compsys' manufacturing process. If BASF and Compsys identify an alternative foam blowing agent before January 1, 2022, Compsys also would commit to notifying EPA of this development and discussing the lead-time for a full transition to the alternative.

c. *Composite Preforming Offers Significant Lifetime GHG Reductions and Improvements in Fuel Economy when Used in Marine and Transportation Applications.*

Compsys' Prisma product results in significant lifetime GHG reductions and offers measureable improvements in vehicle and engine fuel efficiency. Our research, including that conducted jointly with the Department of Defense and U.S. Navy, indicates that Prisma products can achieve a 40-60% overall reduction in boat weight compared to standard fiberglass construction, without sacrificing hull strength. Lighter-weight boats also achieve better fuel economy—reducing U.S. petroleum consumption, GHG emissions, and emissions of other pollutants of concern. Compsys and Structural Composites found that boats built using our technology achieved up to a 40% improvement in fuel efficiency.

Prisma also has great potential for use in the on-road transportation sector, particularly in refrigerated trailers. Prisma is at least 25% more thermally efficient that current trailer fabrications, leading to lower usage of on-board cooling technologies, which in turn means lower overall fuel consumption. Because Prisma is so lightweight yet structurally strong, it can be used as structural components in both refrigerated and standard trailers. Lighter-weight trailers also contribute greatly to overall fuel savings, reduced GHG emissions, and lower emissions of other air pollutants. Prisma also can be used to create structural components for flat-bed trailers, truck bodies, buses, recreational vehicles, and other types of vehicles.

EPA is currently working on a rule to establish more stringent GHG emission standards for heavy-duty trucks and trailers. Our technology has the potential to offer significant overall GHG reductions and fuel savings for this transportation sector. Compsys therefore recommends that EPA establish a temporary narrowed use limit for spray foam composite preforming that would allow the use of HFC-134a until January 1, 2025. This deadline will provide Compsys and Structural Composites with adequate time to research, develop, and implement an alternative foam-blowing agent for products that offer opportunities for achieving significant GHG reductions from the on-road transportation sector.

d. *Very Little HFC-134a is Released into the Atmosphere in the Composite Preforming Process.*

Our preliminary research indicates that approximately one-tenth of the HFC-134a used in our composite preforming process is released into the atmosphere. Our polyurethane foam is sprayed into a mold that is completely encapsulated in a composite coating. Because of the size of the HFC-134a molecule, it cannot pass through the composite coating. Thus, any HFC-134a that reaches the atmosphere occurs during the spray process. Once the foam is enclosed and fully encapsulated, any HFC-134a retained in the foam will be permanently enclosed.

As a result, the GHG emissions and overall global warming potential associated with HFC-134a use in composite preforming are extremely low. Moreover, such GHG emissions are non-

recurring and are negligible in comparison to the overall GHG reductions that will be achieved by improving boat and vehicle fuel economy. Our calculations indicate that use of Prisma preform technology in refrigerated trailers can reduce GHG emissions by approximately 25 tons of CO_2-equivalent per year and 650,000 lbs. of CO_2-equivalent over the useful life of the trailer. Also associated with use of lightweight Prisma products would be hundreds of thousands of gallons of fuel savings.

Due to the great potential for longer-term GHG reductions at the cost of de minimis, near-term emissions of HFC-134a from the foam blowing process, Compsys and Structural Composites urge EPA to continue to allow the use of HFC-134a as a blowing agent for composite preforming until January 1, 2025.

II. EPA Should Finalize the Proposed Prohibition Against the Importation of Products Produced with HFC-134a as the Foam Blowing Agent if Similar Uses Will Be Prohibited Within the U.S.

In the proposed rule, EPA proposed to prohibit the importation of products made with foam if the foam blowing agent for that product and end use was unacceptable for that end-use in the United States. Compsys and Structural Composites strongly urge EPA to finalize this approach.

Compsys and Structural Composites agree with EPA that Clean Air Act Sections 610 and 612 provide EPA with the authority to define the "use" of a closed-cell foam product that contains a blowing agent that EPA has found to be unacceptable for use in the U.S. to include the importation, sale, and installation of such products within the U.S., even if the product was manufactured outside of the U.S. As EPA explained in the proposal, the use of a closed cell foam that contains a prohibited blowing agent constitutes the use of a substance that EPA has found to be unacceptable. Compsys also agrees with EPA that emissions from a closed cell foam product would occur within the U.S. at the time the product is destroyed or at disposal. Therefore, we support EPA's legal rationale for changing the agency's prior interpretation and prohibiting the importation or sale of closed cell foam products in the U.S. no later than one year after the date on which the blowing agent used and contained in the product is unacceptable within the U.S.

As EPA well knows, the effect of a substance with global warming potential is the same regardless of where that molecule is released into the atmosphere. Any reductions in GHG emissions that EPA expects to achieve under the SNAP rule may easily be offset by companies moving production of foam blowing operations outside of the U.S. By continuing to allow importation of foam products produced with blowing agents deemed unacceptable in the U.S., the rule may actually lead to the unintended consequence of *increased* overall GHG emissions—albeit outside of the U.S.

Even leaving aside environmental considerations, EPA's decision to continue to allow imported foam products while prohibiting the same manufacturing processes within the U.S. has massive financial and competitive consequences for the foam blowing industry. Companies with operations located solely within the U.S.—including small businesses such as Compsys and Structural Composites—that contribute to the growth and prosperity of the U.S. economy will be put out of business. Multi-national companies or those that have chosen to site

manufacturing in other nations with less-stringent environmental standards will prosper. If EPA retains the exemption for imported products, then EPA must reconsider the applicability of the final SNAP rule to products manufactured within the U.S. to avoid bankrupting successful, innovative American small business.

*****

Compsys and Structural Composites greatly appreciate the opportunity to comment on this proposed rule. Please do not hesitate to contact me at 321-252-4566 or slewit@aol.com with any questions you may have.

Sincerely,

Scott M. Lewit /AHC

Scott M. Lewit
President
Structural Composites, Inc. and Compsys, Inc.

October 27, 2017

HIGHLIGHTS OF WABASH INVESTMENT IN STRUCTURAL COMPOSITE TECHNOLOGY

- $3M investment in Little Falls, MN to repurpose a former boat plant to produce structural composite components for use in truck bodies and trailers; part of a $10M overall investment to expand production of structural composite components.
- Investment in Minnesota will create 100 jobs over five years, in addition to jobs created through expansion of production capabilities in Lafayette and Frankfort, IN.
- Wabash acquired Supreme Industries at an equity value of $364 million and an enterprise value of $342 million, expanding the ability to deploy structural composite components in truck bodies produced in the U.S.

Wabash National has developed a new Cold Chain series of truck bodies and trailers with advanced molded structural composite technology. The advanced molded structural composite technology is used to create new value propositions within markets where light weighting and strength is critical. Within the cold chain transportation equipment market thermal efficiency from the integration of molded structural composites is also extremely critical. Earlier this year Wabash acquired a facility in Little Falls, MN that was the former Larson Boat plant. The Larson boat plant was scheduled to close but will now be able to produce new Wabash products that utilize molded structural composite products featuring Prisma panels. This new facility will create jobs that would have otherwise left the little falls area. Wabash is investing $3M in Minnesota to scale and commercialize products that utilize this technology as part of a longer-term $10M plan.

More recently Wabash National has closed on the acquisition of Supreme Industries Inc. This is the second largest truck body manufacturer in the United States. Acquiring Supreme will further help Wabash introduce and scale advanced molded structural composites technology into a new space within the transportation equipment market where Wabash hasn't traditionally served. This investment comes at a time when competitors are building new plants in Mexico.

Attached are several articles further discussing the investments Wabash has made in the U.S. to expand the production of truck bodies and trailers using advanced structural composite technology.

October 27, 2017

From July 5th, 2017 :http://compositesmanufacturingmagazine.com/2017/07/wabash-and-structural-composites-make-first-all-composite-trailer/3/

The Trailblazing Trailer

Wabash was first introduced to the possibility of using composites in the trailer by Structural Composites, a Melbourne, Fla.-based company that was using unique composite technology for shock-mitigating Navy boats. Wabash assessed performance and economic metrics, then benchmarked how the technology might apply to trailers.

Wabash used Structural Composites' PRISMA® as the main material for the trailer's entire box, which consists of the roof, walls, nose and floor. This provides excellent insulation qualities at a lower weight than conventional sandwich materials and has the necessary scalability to service a large market. CFRP can also be selectively utilized in the trailer to further reduce weight.

In addition to PRISMA, Wabash used Structural Composites' CoCure strain tunable coating technology for the trailer's interior and exterior wall, roof surfaces and interior floor. The technology allows polyester resins and coatings to be combined with polyurethanes on the factory floor. The strain tuning aspect refers to the ability to change the urethane blend ratio, thereby altering the resin properties – in particular, the strain to failure.

By incorporating molded structural composites instead of aluminum, Wabash improved the trailer's overall thermal performance by up to 25 percent. The trailer's floor is also up to 20 percent lighter than it would be with steel, and the system is far more puncture- and damage-resistant than conventional constructions. In addition, the company indicates that using molded structural composites for the floor system means the trailer can handle more weight – up to 24,000 pounds – compared to conventional refrigerated vans that are rated for up to 16,000 pounds.

October 27, 2017

For Wabash, all those advantages translate to a financially-viable solution. One of the biggest barriers to the integration of composites in the trailer industry has been cost. Many resins are cost-effective but suffer from poor mechanical properties. Structural Composites' PRISMA and CoCure technologies give Wabash scalable technology that provides great performance at an affordable price. The properties of the trailer, in turn, mean increased savings for Wabash's customers. Customers are also attracted to the possibility of hauling less weight down the road, which also leads to greater fuel efficiency.

Feb 09,2017

Wabash National Corporation to Expand Operations to Minnesota with Advanced Composites Manufacturing Facility

LAFAYETTE, Ind. – Feb. 9, 2017 – Wabash National Corporation (NYSE: WNC), a diversified industrial manufacturer and North America's leading producer of semi-trailers and liquid transportation systems, today announced plans to invest more than $3 million for a manufacturing facility in Little Falls, Minnesota, as part of a $10M longer-term plan to expand production operations for molded structural composites (MSC).

"In support of the continued success of our strategic growth and diversification efforts in advanced composites, we're making this next step in our multi-year development plan to commercialize molded structural composites for select parts of the trailer and truck body markets," said Dick Giromini, chief executive officer. "We want to express our appreciation to Little Falls Mayor Zylka and city officials for their support on this project. We look forward to joining area businesses as an economic contributor and community supporter."

After considerable evaluation of potential expansion opportunities across the United States, Wabash National is purchasing the Little Falls facility from Larson Boat Group. Wabash National selected the Little Falls location as the launch facility for MSC products because of the unique combination of an experienced and highly skilled workforce in composite manufacturing processes, along with a fully equipped and highly engineered facility capable of producing large-size parts at high rates of volume.

Combining this composites manufacturing capability with Wabash National's R&D expertise in advanced composites will allow the company to begin scaling MSC technology across multiple product categories.

"We remain committed to transforming Wabash National into a more diversified industrial company with a broader array of products and services. Our expanding portfolio of composite offerings is instrumental to that goal," explained Brent Yeagy, president and chief operating officer. "The expansion of our MSC manufacturing capabilities, as well as our new licensed ThermHex honeycomb core composite technology that we announced last year, highlight this growing competency in advanced composites."

Wabash National expects to create more than 100 jobs in Little Falls over the next five years, while continuing to grow its other composites manufacturing operations in Lafayette and Frankfort, Indiana. The company expects to take ownership of the property in April 2017

Aug 08,2017

Wabash National Corporation Announces Agreement to Acquire Supreme Industries, Inc.

- Accelerates Wabash National's organic growth in the approximately $2.0B final mile equipment segment

October 27, 2017

- Builds on Supreme's 43-year heritage of truck body manufacturing and customer service, with Wabash National adding new technologies and innovation, manufacturing optimization and cost synergies
- Larger manufacturing footprint and diverse portfolio better serves customers of both companies
- Accretive in first full calendar year after close
- Delivers on Wabash National's strategic plan to diversify the business

LAFAYETTE and GOSHEN, Ind. – Aug. 8, 2017 – Lafayette, Ind.-based Wabash National Corporation (NYSE: WNC), a diversified industrial manufacturer and North America's leading producer of semi-trailers and liquid transportation systems, and Goshen, Ind.-based Supreme Industries, Inc. (NYSE MKT: STS), a leading manufacturer of truck bodies, announced that they have entered into a definitive agreement under which Wabash National would acquire all of the outstanding shares of Supreme in a cash tender offer for $21 per share, which represents an equity value of $364 million and an enterprise value of $342 million.

Founded in 1974, Supreme is the second largest U.S. manufacturer of truck bodies with 2016 sales of $299 million. The company primarily manufactures light- and medium-duty truck bodies at seven facilities throughout the United States.

"Wabash National has been closely monitoring the transportation landscape as the growth of e-commerce has continued to change the logistics model," said Dick Giromini, Wabash National's chief executive officer. "We formally entered the final mile space in 2015 with the launch of our dry and refrigerated truck bodies, and we have been aggressively growing our presence and product offering over the past two years. This acquisition supports these efforts and accelerates our objective to transform our business into a more diversified industrial manufacturer."

The acquisition will combine Supreme's extensive medium- and light-duty commercial vehicle portfolio, distribution network, and regional manufacturing locations with Wabash National's advanced composite technologies, expertise in lean manufacturing and optimization, engineering and design proficiency and strong supplier relationships.

Supreme provides Wabash National with significant growth and diversification benefits, in line with the company's long-term strategic plan, including reduced dependence on dry van trailer demand, reduced cyclicality and new segments for growth.

Wabash National intends to build upon Supreme's industry leadership, distributed manufacturing and installed sales force capacity to accelerate its successful organic truck body growth initiative, while preserving Supreme's heritage of excellence in serving customers.

"This is a great opportunity for both companies to combine our strengths to provide an enhanced customer experience within the growing final mile delivery space," Giromini added. "With Supreme, not only can Wabash National accelerate organic growth with our innovative DuraPlate®, honeycomb panel and molded structural composite (MSC) truck bodies, we can also provide a broader conventional product offering to our existing customer base."

Wabash National expects to deliver at least $20 million in annual run-rate cost synergies by 2021. The expected cost synergies are primarily driven by corporate and procurement expenditures, and operational improvement savings. In addition, over time, Wabash National expects to achieve significant incremental revenue opportunities that neither company could obtain on a standalone basis.

Supreme Industries' Chief Executive Officer Mark Weber commented, "This is an exciting day for Supreme. Combining with Wabash will enhance our ability to innovate more quickly and create more value for customers. We found a cultural fit with Wabash National. Because of their commitment to safety, innovation and customer relationships, I'm confident joining the Wabash National family will benefit our employees, customers and distributors."

Message

From: Atkinson, Emily [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=BB2155ADEF6A44AEA9410741F0C01D27-ATKINSON, EMILY]
Sent: 11/7/2017 2:51:02 PM
To: Shaw, Betsy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=31ca1476a7674825a131cb2c0d6c88c8-BShaw03]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Travel for Mandy Gunasekara to the Texas Industry Project Meeting in Houston, TX from 12/6 - 7
Attachments: FW: Texas Industry Project meeting invite: 12/7/17

Hi Betsy,

Mandy Gunasekara is planning to travel to the Texas Industry Project Meeting from Wednesday, December 6 - Thursday, December 7, 2017 to give the luncheon keynote address. Attached is the invite for your review.

Please advise if you authorize her for travel.

Thank you.
Emily

Emily Atkinson
Management Analyst/Office Manager
Immediate Office of the Acting Assistant Administrator
Office of Air and Radiation, USEPA
Room 5412B, 1200 Pennsylvania Avenue NW
Washington, DC 20460
Voice: 202-564-1850
Email: mailto:atkinson.emily@epa.gov

Message

From: Coleman, Sam [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=8246A5315FF54185AC8C8BF90D5A393E-COLEMAN, SAM]
Sent: 10/31/2017 4:14:42 PM
To: Spencer, Stuart [SPENCER@adeq.state.ar.us]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Stenger, Wren [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=c109285f44b14f70a224be41ab99e9e2-Stenger, Wren]; Donaldson, Guy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=d2a0969773664cc3b6eb1208748f1a5d-Donaldson, Guy]; Medina, Dayana [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=ddea406f71f24558b60679db3f5ce386-Medina, Dayana]; Nann, Barbara [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=b87a421478d34284b483ca215d219e2f-Nann, Barbara]
Subject: Re: AR Regional Haze - Phase II SIP

Thanks

Samuel Coleman, P. E.,
Deputy Regional Administrator

214.665.2100 Ofc
214.665. 3110 Desk
Personal Phone / Ex. 6 Cell

Coleman.sam@epa.gov

Sent from my iPhone

On Oct 31, 2017, at 10:27 AM, Spencer, Stuart <SPENCER@adeq.state.ar.us> wrote:

FYI. ☺

From: Jamie Ewing [mailto:jamie.ewing@arkansasag.gov]
Sent: Tuesday, October 31, 2017 10:07 AM
To: Spence, Samara (ENRD) (Samara.Spence@usdoj.gov); tony.mendoza@sierraclub.org; Matthew Gerhart (Personal Email / Ex. 6); joshua.smith@sierraclub.org; Charles McPhedran (cmcphedran@earthjustice.org); alan@ppgmrlaw.com; Kim@ppgmrlaw.com; Chad Wood (chad@ppgmrlaw.com); kmcque1@entergy.com; twebster@sidley.com; debra.jezouit@bakerbotts.com; mnasi@jw.com; Jennifer Loiacano (Jennifer.Loiacano@aecc.com); lori.burrows@aecc.com; Stephanie Kodish (skodish@npca.org)
Cc: Spencer, Stuart; Montgomery, William; Sarah Tacker; Nicholas Bronni
Subject: AR Regional Haze - Phase II SIP

Counsel,

Please find below links to the public review draft of the Phase II Regional Haze SIP for Arkansas (due to size, I cannot transmit the documents by email). This draft SIP will be published in the Arkansas Democrat-Gazette today. The public notice and comment period will run until January 2, 2018. A public hearing on the Phase II SIP will also be held on January 2, 2018 at the ADEQ Headquarters in North Little Rock, Arkansas. The public hearing will start at 2:00 pm.

https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx
https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/public-review-package.pdf

Please let me know if you have any questions.

Thank you,
Jamie

Jamie Leigh Ewing
Assistant Attorney General
Office of Arkansas Attorney General Leslie Rutledge

323 Center Street, Suite 200
Little Rock, Arkansas 72201
Office: 501.682.5310 | Fax: 501.682.3895
jamie.ewing@arkansasag.gov | ArkansasAG.gov

<image001.png><image002.png> <image003.png> <image004.png> <image005.png> <image006.png>

*****CONFIDENTIALITY NOTICE*****

This e-mail may contain information that is privileged, confidential, or otherwise exempt from disclosure under applicable law. If you are not the addressee or it appears from the context or otherwise that you have received this e-mail in error, please advise me immediately by reply e-mail, keep the contents confidential, and immediately delete the message and any attachments from your system.

Message

From: Hawk Personal Email / Ex. 6
Sent: 11/1/2017 4:18:04 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Fwd: Mark Carr
Attachments: CV Hawk 2017 .pdf; Hawk resume 2017.pdf

Hi Mandy,
Sorry I didn't see you yesterday at Pruitt's announcement. I did see your boss. The announcement was great. I was very happy with outcome. Much needed.
Also, last time we met you mentioned I should meet at the Senate Elizabeth Horner. Could you provide an introduction via email for me?
Thank you,
Hawk

Begin forwarded message:

From: Angelique Hawk Personal Email / Ex. 6
Subject: Mark Carr
Date: October 11, 2017 at 8:48:59 AM EDT
To: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>

Good Morning Mandy,

Personal Matters / Ex. 6

I've attached my resume and CV. Thank you for offering to disseminate to the appropriate people. Your suggestion of the Research and Development or Solid Waste and Pollution Departments sound like perfect fits for me. I found this opening at EPA and was wondering if this was the way you were suggesting I go: https://www.usajobs.gov/GetJob/ViewDetails/479711100/ . I am open to any additional suggestions or recommendations that you think may prove helpful. Any further guidance would be greatly appreciated, but it nothing comes to mind, I'll be sure to keep you posted on my progress over the coming weeks.

Also, you mentioned Elizabeth Corner as a person I should network with. Could you provide an introduction via email to her for me?

Lastly, if there is anything I can ever do for you please let me know.

Thank you,

Hawk

PS: next week is a Cooler Heads meeting. Thank you for mentioning the group to me.

Message

From: Kalee Kreider Personal Email / Ex. 6
Sent: 11/5/2017 12:39:30 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Michael McKenna [mike@mwrstrat.com]; Bolen, Brittany [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=31e872a691114372b5a6a88482a66e48-Bolen, Brit]
Subject: Re:

Hi there!
I drew the short straw and land on the 8th.
I have lost count of how many times I have been to Bonn. So many intercessionals and COP 6 Bis (after 2000). There's good white wine and kolsch beer. And, uh, cheese.
Happy to help in any way including just to be a friendly face. Mobile is Personal Phone / Ex. 6
Do you have someone giving you an update of which reporters are there and overall lay of the land? Kalee

Sent from my iPhone

> On Nov 4, 2017, at 3:48 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>
> Mike, thanks for the connection. Kalee, when do you head out? It would be good to connect once out there. Brittany and I land on the 12th.
> Best,
> Mandy
>
> Sent from my iPhone
>
>> On Nov 4, 2017, at 4:09 PM, Michael McKenna <mike@mwrstrat.com> wrote:
>>
>>
>> Kalee —
>>
>> Mandy and Brittany are headed to Bonn. I think it would be very helpful for them if you could take a moment and share with them your experiences. and perhaps include them in appropriate functions there, as well.
>>
>> Thanks!
>>
>> MMcKenna
>>

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 10/26/2017 3:20:39 PM
To: Traci Kraus [traci.kraus@cummins.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Thank you and follow up- Cummins and EMA

The 10th she is unavailable. On NOx we can set up an AM call the week of the 20th but for a meeting we are unfortunately looking at December.

Sent from my iPhone

On Oct 26, 2017, at 10:59 AM, Traci Kraus <traci.kraus@cummins.com> wrote:

> Hi Alex,
>
> Thanks so much for following up. We understand it's a busy time. Any chance a time on the 10th works? Separately, I know the EMA group would love to come back in to follow up on the CEO meeting with Administrator Pruitt and share more information on low NOx. Is there a date or time that works well for Mandy in the next month or so for that meeting?
>
> Thanks so much for your help!
>
> Best,
>
> **Traci Kraus**
> Director, Government Relations
> Cummins Inc.
>
> 601 Pennsylvania Ave. NW
> Suite 1100N
> Washington, DC 20004
> Office: 202-654-4285
> Cell: 202-302-5851
>
> ---
>
> **From:** Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
> **Sent:** Wednesday, October 25, 2017 7:23 PM
> **To:** Traci Kraus <traci.kraus@cummins.com>
> **Cc:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Re: Thank you and follow up- Cummins and EMA
>
> External Sender
>
> Traci - unfortunately we are unable to make the 9th work Mandy. She is going to be on travel the following week and there are several mandatory meetings she must attend beforehand.

Alex

Sent from my iPhone

On Oct 25, 2017, at 2:13 PM, Traci Kraus <traci.kraus@cummins.com> wrote:

> Thank you Mandy and Alex, appreciate the help! We can be flexible if needed. Let me know what works on your end.
>
> Sent from my iPhone
>
> On Oct 25, 2017, at 11:08 AM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>
> External Sender
>
> Hi Traci,
> I apologize for the delayed response. I do not believe I am available during that time. I'm looping in Alex to help see if we can make it work. We will follow-up in a few.
> Best,
> Mandy
>
> ---
>
> **From:** Traci Kraus [mailto:traci.kraus@cummins.com]
> **Sent:** Tuesday, October 10, 2017 3:37 PM
> **To:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** RE: Thank you and follow up- Cummins and EMA
>
> Hi Mandy,
>
> Hope all is well. I wanted to follow up on the invitation to speak to the EMA/ DTF joint meeting on November 9th. We have separately confirmed that Mike Catanzarro will also be speaking on the Administration's energy and environment priorities, and it would be great to get the EPA perspective.
>
> Specifically we are looking at **1:45 pm- 3:00 pm on November 9th.**
> Please let me know if you might be available.
>
> Thanks so much for your help.
>
> Best,
>
> **Traci Kraus**
> Director, Government Relations
> Cummins Inc.
>
> 601 Pennsylvania Ave. NW
> Suite 1100N
> Washington, DC 20004
> Office: 202-654-4285

Cell: 202-302-5851

From: Traci Kraus
Sent: Tuesday, September 26, 2017 10:04 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Thank you and follow up- Cummins and EMA

Hi Mandy,

I wanted to thank Administrator Pruitt, you and your team for meeting with the principals of the Truck and Engine Manufacturers Association last week. I know the group really appreciated it and thought it was a great and informative meeting.

I know there was a particular follow up regarding the opportunity for a low-NOx rulemaking and streamlining of the heavy duty truck program. Our technical teams are working on follow up information and data and would like the opportunity to present it to you late next month or early November. I wanted to see if we could get something on the schedule. Please let me know what works for you.

I also wanted to extend an invitation for you to address a joint meeting between the Diesel Technology Forum (DTF) and Truck and Engine Manufacturers Association (EMA) on **November 9th or 10th.**

Attendees will be primarily government affairs, engineering and federal and state policy representatives of engine and truck manufacturers, off-road equipment makers, suppliers and emissions control technology companies and some fuel interests as well. Among the companies expected to attend are Caterpillar, Cummins, Daimler, Deere, CNH, Volvo, GM, Ford, Isuzu, Bosch, Delphi, AGCO, MTU, Navistar and several others. We expect an audience of about 50 people from those companies all with a substantial interest in both domestic energy and environmental policy as well as international issues. The meeting is private and not open to members of the public or press. It will be held at the law offices of Crowell and Moring, located at 1001 Pennsylvania Avenue NW.

We would love to hear you speak about EPA's priorities and how the industry can continue to work collaboratively with the Administration. We have availability in the schedule on the afternoon of Thursday, November 9th, or the morning of Friday, November 10th. Please let me know if you might be available, or if there is a more formal channel through which I should make the request.

Again, thanks so much for all of your help!

All the best,

Traci Kraus
Director, Government Relations
Cummins Inc.

601 Pennsylvania Ave. NW
Suite 1100N
Washington, DC 20004
Office: 202-654-4285
Cell: 202-302-5851

Message

From: John Moran [Personal Email / Ex. 6]
Sent: 10/31/2017 2:53:55 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Fiona [Personal Email / Ex. 6]; surya.gunasekara[Personal Email / Ex. 6]
Subject: Re: Old Town Halloween 2017

Absolutely. We'd love to have you!

Sent from my iPhone

On Oct 30, 2017, at 6:42 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

Hey John,

Personal Matters / Ex. 6

Best,
Mandy

Sent from my iPhone

On Oct 9, 2017, at 11:18 PM, John Moran [Personal Email / Ex. 6] wrote:

Merrymakers,

Personal Matters / Ex. 6

Hope to see you there!

John Moran

Message

From: Williams, Brendan [Brendan.Williams@pbfenergy.com]
Sent: 10/31/2017 3:11:07 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: FW: BIOFUELS UPDATE: ***Obligated Parties May Need Carryover RINs Bank to Meet 2017 Targets: Report

Mandy-

Hope all is well. Wanted to make sure you saw the note below. Note that this is from the University of Illinois and indicates RIN generation is not keeping up with the mandate. As always, let me know if you have any questions.

Thanks,
Brendan

From:
Sent: Monday, October 30, 2017 4:07 PM
To:
Subject: BIOFUELS UPDATE: ***Obligated Parties May Need Carryover RINs Bank to Meet 2017 Targets: Report

2017-10-30 03:57:56 EDT
***Obligated Parties May Need Carryover RINs Bank to Meet 2017 Targets: Report

Obligated parties under the Renewable Fuel Standard (RFS) might have to dip into the bank of carryover Renewable Identification Number (RIN) credits to meet compliance obligations in 2017 if the pace of new RIN generation doesn't pick up substantially in the closing months, the University of Illinois said in a an analysis Friday.

Although gross generation of RINs across all D-code categories designated by the U.S. Environmental Protection Agency (EPA) has increased each quarter in 2017, net generation of D6 RINs is projected to fall short of the renewable mandate component by 400 million to 500 million RINs, according to the analysis published on Farmdoc Daily by Nick Paulson of the school's Department of Agricultural and Consumer Economics.

"If the pace of RIN generation and/or exports do not adjust over the fourth quarter to result in sufficient 2017 RINs, the use of existing RIN stocks may be needed for 2017 compliance purposes," Paulson said.

D6 RINs are primarily generated through the blending of corn-based ethanol into the gasoline pool.

Monthly gross generation of D6 RINs in the third quarter increased to an average of 1.27 billion RIN/month, up from just over 1.23 billion RINs/month in the first half of the year. At that rate, Paulson estimated that nearly 15 billion RINs will be generated this year.

But backing out exports of denatured ethanol -- which exceeded 285 million gal through August -- results in a net generation estimate of approximately 14.5
billion-14.6 billion D6 RINs, short of the 15 billion non-advanced or renewable mandate component for 2017, Paulson said. RINs attached to exported denatured ethanol are retired and cannot be used for RFS compliance under EPA rules.

In EPA's July proposal for the 2018 Renewable Volume Obligations (RVOs), the agency estimated the number of carryover RINs at 2.06 billion but also emphasized the important role that the carryover RINs bank serves as a "...

programmatic buffer that both facilitates individual compliance and provides for smooth overall functioning of the program."

Earlier this month, EPA Administrator Scott Pruitt provided key concessions to the biofuels industry in a letter to seven Midwest Republican senators, saying the agency will likely issue final 2018 RVOs at or above levels it proposed in July. That would set the implied volume for conventional renewable fuel at 15 billion gal, consistent with the statutory targets provided for 2017.

Generation of D6 RINs in September fell 7.45% from August to a five-month low of 1.227 billion RINs, EPA data showed last week. D6 RIN generation in September trailed that of September 2016 by 2.2% and through the first nine months of 2017, the 11.24 billion D6 RINs generated are 0.72% below where they were over the same period of 2016.

D6 RINs prices have strengthened over the last month following Pruitt's recommitment to promises made about maintaining a strong RFS. D6 RINs for 2017 were assessed by OPIS at 97.13cts/RIN on Friday, up from 72cts/RIN a month earlier.

DISCLAIMER: This e-mail message and any attachments are intended solely for the use of the individual or entity to which it is addressed and may contain information that is confidential or legally privileged. If you are not the intended recipient, you are hereby notified that any dissemination, distribution, copying or other use of this message or its attachments is strictly prohibited. If you have received this message in error, please notify the sender immediately and permanently delete this message and any attachments.

Message

From: Wilcox, Jahan [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=88FD588E97D3405D869BCAE98D391984-WILCOX, JAH]
Sent: 10/31/2017 3:03:40 PM
To: Eric Wolff [ewolff@politico.com]
CC: Bowman, Liz [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=c3d4d94d3e4b4b1f80904056703ebc80-Bowman, Eli]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Abboud, Michael [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=b6f5af791a1842f1adcc088cbf9ed3ce-Abboud, Mic]
Subject: RE: RFS meeting

Defer these questions to the White House, since that is where he sent his letter.

From: Eric Wolff [mailto:ewolff@politico.com]
Sent: Tuesday, October 31, 2017 11:00 AM
To: Press <Press@epa.gov>
Subject: RFS meeting

Hi all,

Last week Sen. Ted Cruz sent a letter to the White House asking for a meeting brokered by the White House between 9 oil state senators and 7 midwestern senators.

Today he told a colleague that discussions are ongoing to set up the meeting.

Is Administrator Pruitt part of those discussions? I.e. is he planning on attending the meeting?

Thanks,

Eric

--
Eric Wolff
Energy Reporter
POLITICO
760-303-1927
ewolff@politico.com
@ericwolff

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 10/23/2017 4:06:20 PM
To: George Cooper [gcooper@forbes-tate.com]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Jeff Sadosky [jsadosky@forbes-tate.com]
Subject: RE: NMMA Meeting Request

George – Mandy in unfortunately unable to meet this week. The soonest availability would be for a call on Friday, November 10th at 11:30AM or 2:00PM EDT. Please let me know if either of those work.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to the Administrator for Air and Water
U.S. Environmental Protection Agency

From: George Cooper [mailto:gcooper@forbes-tate.com]
Sent: Monday, October 23, 2017 10:19 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Jeff Sadosky <jsadosky@forbes-tate.com>
Subject: Re: NMMA Meeting Request
Importance: High

Mandy and Alex I am checking back to see if we might be able to pull together a meeting for Wednesday afternoon or Thursday. Since sending this request last week NMMA has taken a look at the letter from Administrator Pruitt to the corn belt senators and in particular the paragraph regarding E15. We of course have members asking about this and so are even more anxious to visit with you and/or appropriate colleagues about the huge stakes at hand when it comes to putting E15 into market during the most popular summer boating months.
NMMA President Thom Dammrich is in town on Wednesday and Thursday so I am hoping we can find a time that works.
Thank you both,
George Cooper

From: George Cooper <gcooper@forbes-tate.com>
Date: Thursday, October 19, 2017 at 3:30 PM
To: "Gunasekara.Mandy@epa.gov" <Gunasekara.Mandy@epa.gov>, "dominguez.alexander@epa.gov" <dominguez.alexander@epa.gov>
Subject: NMMA Meeting Request

Mandy and Alex you met with several members of the National Marine Manufacturers Association earlier this year – as you may recall Administrator Pruitt Personal Matters / Ex. 6 ended up joining us for some of the productive discussion. We covered several subjects that day, spending some time on ethanol and E15 in particular. Wondering if some NMMA reps can come in to see you and/or any of your colleagues you think

appropriate to expand on our recent thinking regarding E15 and a few other biofuel related matters. Looking at Wednesday or Thursday next week if possible.
Thank you very much!
George

George Cooper
Forbes Tate Partners
777 6th Street, NW, 8th Floor
Washington, DC 20001
O: 202-638-0125
C: 703-371-5572
F: 202-638-0115
www.forbes-tate.com

FORBES | TATE
PARTNERS

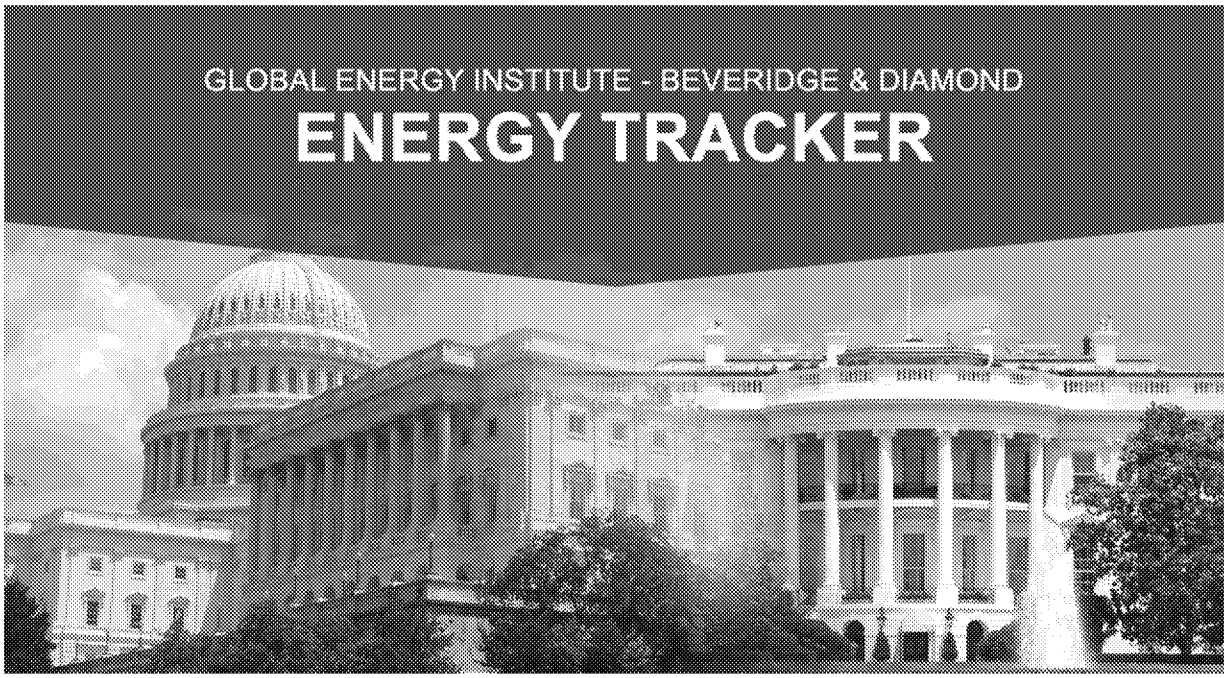
Message

From: Global Energy Institute [globalenergy@uschamber.com]
Sent: 10/27/2017 5:57:38 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Energy Round Up

Energy Roundup

The Energy Tracker is Here

As the Trump Administration moves forward with an ambitious energy and environmental reform agenda, the Global Energy Institute and the law firm Beveridge & Diamond have launched a comprehensive Energy Tracker to help follow key regulatory, judicial and legislative developments. Check it out here!

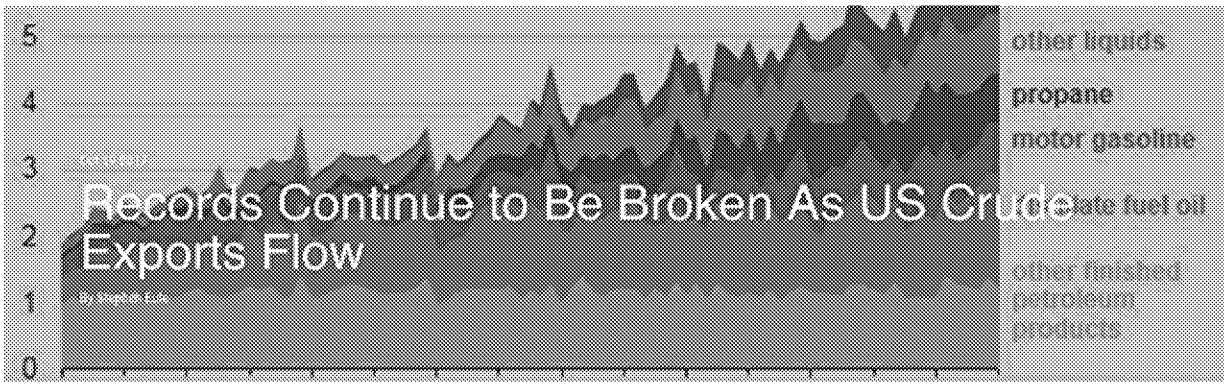


GEI on the Road: Chicago

GEI's Christopher Guith was on the road in Chicago talking to state and local chambers about the latest in US energy policy.

Fuel for Thought

This month, we released our new blog, **Fuel for Thought**, which features deep dives into energy policies and regulations from Congress and the Administration, details on our latest reports, energy explainers and insights. Check out Stephen Eule's latest blog on America's increasing crude exports and the subsequent benefits to our economy, job growth and more. If you like what you read, sign up to keep up with new blog posts!



Sign Up Here

Share this email:

Manage your preferences | Opt out using TrueRemove™
Got this as a forward? Sign up to receive our future emails.
View this email online.

1615 H Street, NW
Washington, DC | 20062 US

This email was sent to gunasekera.mandy@epa.gov.
To continue receiving our emails, add us to your address book.

"U.S. CHAMBER" and "U.S. CHAMBER OF COMMERCE" are registered trademarks of the Chamber of Commerce of the United States of America.

Message

From: Peter M. Robinson [probinson@uscib.org]
Sent: 11/7/2017 3:56:30 PM
To: campbellH1@state.gov
CC: EOP / Ex. 6 talleyt@state.gov; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Bolen, Brittany [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=31e872a691114372b5a6a88482a66e48-Bolen, Brit]
Subject: Letter from the United States Council for International Business (USCIB) on COP23 for Undersecretary Thomas Shannon
Attachments: cc PR letter to U-S Shannon.pdf; BizMEF Perspectives on COP-23 Final Formatted.pdf; Building Foundations Final Formatted.pdf; Business and COI in UNFCCC Final Formatted.pdf; ICC COP23 Policy Statement.pdf

Dear Under Secretary Shannon,

Please find attached a letter from the United States Council for International Business (USCIB) encouraging robust U.S. engagement at the 23rd Conference of the Parties (COP23) in Bonn. We appreciate your continued efforts to advance American economic interests at home and overseas throughout the negotiations.

Best regards,
Peter

Peter M. Robinson
President and CEO
United States Council for International Business (USCIB)
1212 Avenue of the Americas, New York, NY 10036
Tel: +1 212 703-5046 Fax: +1 212 575-0327
probinson@uscib.org
==========
Global Business Leadership as U.S. Affiliate of:
- International Chamber of Commerce
- International Organization of Employers
- Business and Industry Advisory Committee to the OECD
- ATA Carnet System

Disclaimer

The information contained in this communication from the sender is confidential. It is intended solely for use by the recipient and others authorized to receive it. If you are not the recipient, you are hereby notified that any disclosure, copying, distribution or taking action in relation of the contents of this information is strictly prohibited and may be unlawful.

This email has been scanned for viruses and malware, and may have been automatically archived by **Mimecast Ltd**, an innovator in Software as a Service (SaaS) for business. Providing a **safer** and **more useful** place for your human generated data. Specializing in; Security, archiving and compliance. To find out more Click Here.

Message

From: Chris Sarley [csarley@cgagroup.com]
Sent: 10/26/2017 5:12:56 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Circling Back - Help connecting me with the right EPA Staff?

Sounds good. And Thank you.

On Oct 26, 2017, at 1:07 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

2:45

Use my conference line: Personal Phone / Ex. 6
Code: Personal Phone / Ex. 6

From: Chris Sarley [mailto:csarley@cgagroup.com]
Sent: Thursday, October 26, 2017 12:40 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Circling Back - Help connecting me with the right EPA Staff?

For sure. Give me a time and I'll coordinate with Our Kirby guy to get him on the phone.

You need me to set up a conference line or have a number for us to call?

On Oct 26, 2017, at 12:24 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

Do you have time to chat today? I have some time after 3:30. Does that work?

From: Chris Sarley [mailto:csarley@cgagroup.com]
Sent: Thursday, October 26, 2017 9:59 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Circling Back - Help connecting me with the right EPA Staff?

Hi Mandy – coming back to you on this issue as Kirby is under an end of the month deadline. With the background information on the situation provided we were seeking a dialogue to prevent just blindly filing the application again for consideration. Is there an opportunity for us to set up a call or meeting to provide any additional information or clarification? Kirby just wanted to ensure a decision this time one way or another is made with the full picture in mind. Thanks in advance – Chris

PS: I think they have full court press on so you might expect hearing from any or all of Culberson, Flores, Olson offices. I believe they spoke to some of Senator Inhofe's folks as well given their footprint with him.

From: Chris Sarley
Sent: Monday, October 16, 2017 11:30 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Circling Back - Help connecting me with the right EPA Staff?

Hey Mandy – Hope you had a nice weekend. Wanted to refresh at the top of your inbox to see if you have had a chance to digest this yet and answer any questions you might have so we can get your sense of best next steps for us. Thanks – Chris

From: Chris Sarley
Sent: Tuesday, October 10, 2017 12:45 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: 'Jackson, Ryan' <jackson.ryan@epa.gov>
Subject: RE: Circling Back - Help connecting me with the right EPA Staff?

Hi Mandy! Ryan thanks for looping us all in.

Kirby stands ready to file the application, we just want to make sure we were sequencing things correctly. The hesitation stems from EPA career staff previously taking a position with Kirby that an acquisition cannot be the primary reason for hardship relief, although there is no statutory prohibition for using an acquisition as the basis of hardship relief. Before just submitting the application to flow through those channels again we wanted to ensure they were presenting their legal justification in the correct manner to the right EPA personnel.

Mandy – more information below and attached. Let me know what you think is best and we will heed your advice on how best to proceed.

Thanks – Chris

From: Jackson, Ryan [mailto:jackson.ryan@epa.gov]
Sent: Tuesday, October 10, 2017 12:10 PM
To: Chris Sarley <csarley@cgagroup.com>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Circling Back - Help connecting me with the right EPA Staff?

Mandy is the best person and maybe daubs Harlow can now be read into this.

However, I think if they can submit their application it will help us to refine that further to get it permitted.

_____
Ryan Jackson
Chief of Staff
U.S. EPA
Personal Phone / Ex. 6

On Oct 10, 2017, at 11:50 AM, Chris Sarley <csarley@cgagroup.com> wrote:

Hey man – circling back on the Kirby issue from a few weeks ago. I think by now you have probably heard from Culberson and Flores folks on the House side and Cornyn's staff on the Senate looking into this a little more. Unfortunately there is a bit of a time crunch to have this resolved by the end of the month in order for Kirby to build and deliver units by the end of the year. The final application is prepared and will be ready to file with EPA. That being said, before Kirby sends the application to EPA I wanted to get some feedback and direction from you to help us figure out who to discuss with on your team and determine how best to proceed before entering into that formal process.

Appreciate any guidance you can provide to steer us toward the right discussion. – Sarley

---

From: Chris Sarley
Sent: Tuesday, September 26, 2017 10:55 AM
To: jackson.ryan@epa.gov
Subject: Help connecting me with the right EPA Staff?

Ryan – hope all is well my man. Been a long time since we've been able to catch up, I'm sure you're in a constant state of busy but hopefully we can all find some time soon. I work with your former colleague at EPW, Lazer (great guy) and he said he caught up with you out a couple times with some of team Inhofe so I know we can make it happen. That aside, I had an EPA related issue I was hoping you could connect me with the right people on your team to discuss with. I've attached a full summary of the situation but briefly:

Kirby Corporation has a waiver issue arising from a recent acquisition of a company Stewart and Stevenson (S&S). Both companies participate in the EPA "Transition Program for Engine Manufacturers" using the "single family compliance option." This allows each company to use a certain number of Tier 2 engines from a single manufacturer during the period of the program, which expires at the end of 2017. S&S entered into contracts before the Kirby acquisition to produce equipment using engines it obtained under the program. EPA regulations stipulate that post-acquisition, S&S must use engines that are the same as Kirby's other engine subsidiaries. Problem arising in S&S cannot satisfy its existing contractual obligations using the other engine. Reasoning being, this is the only engine in their frac fleet so their entire maintenance and parts system is built around supporting this engine. The engines are in S&S's inventory and ready to be installed as the units are constructed. Kirby cannot meet its acquired contractual obligations except by using these engines.

We were seeking a dialogue with EPA staff you have brought in on the team about a hardship provision that currently exists giving EPA the discretion to allow relief. It is my understanding that EPA career staff has previously taken a position that an acquisition cannot be the

primary reason for hardship relief, although there is no statutory prohibition for using an acquisition as the basis of hardship relief. Kirby maintains that the law allows the hardship exception in this case which in turn will mean contractual obligations can be met and keep workers employed building products that customers need.

Appreciate it if you can help me identify the right folks at EPA to engage on this with. Kirby is positions to submit their application on a rapid timeline so we can make any in person or conference call happen immediately. As a head's up they are also getting in touch with Culberson and Cornyn to engage on the issue so you might get some inquires coming your way from the hill as well.

Thanks in advance – I really appreciate it – and let me know if there is anything else you need from my end to set something up with Kirby.

- <!--[if !supportLists]--><!--[endif]-->Chris

Chris Sarley | Vice President
<image001.jpg>
Annapolis | Atlanta | Austin | Baton Rouge | Chicago | Des Moines
Houston | Jackson | Richmond | Springfield | **Washington**

202.448.9511 Direct | 202.494.0960 Mobile | 202.448.9500 Office

300 Independence Avenue, SE
Washington, DC 20003

www.cgagroup.com | @CGAgroup

<Kirby Engine Issue Summary.pdf>

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 10/30/2017 8:24:55 PM
To: Anne Steckel Personal Email / Ex. 6
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting Request Oct 23rd or 24th- Pilot Flying J

Great. Confirmed for Tuesday, November 11th at 2:30PM EDT.

Conference Line: Personal Phone / Ex. 6
Passcode: Personal Phone / Ex. 6

Alex

From: Anne Steckel Personal Email / Ex. 6
Sent: Monday, October 30, 2017 4:09 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Meeting Request Oct 23rd or 24th- Pilot Flying J

Yes, that's great, thanks

-Anne

On Oct 30, 2017, at 3:54 PM, Dominguez, Alexander <dominguez.alexander@epa.gov> wrote:

> She is no longer available at 2:00 – can you do 2:30?
>
> ---
>
> **From:** Anne Steckel Personal Email / Ex. 6
> **Sent:** Monday, October 30, 2017 12:09 PM
> **To:** Dominguez, Alexander <dominguez.alexander@epa.gov>
> **Cc:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Re: Meeting Request Oct 23rd or 24th- Pilot Flying J
>
> Hi Alex,
>
> Let's do the call on Nov 7th at 2pm. Please let me know the best number to use.
>
> Thanks, the folks at Pilot Flying J have some ideas on how they can be helpful.
>
> Thanks
> Anne
>
> Anne Steckel
> Ardent Strategies
> 202.422.4002

From: "Dominguez, Alexander" <dominguez.alexander@epa.gov>
Date: Monday, October 23, 2017 at 10:58 AM
To: Anne Steckel Personal Email / Ex. 6
Cc: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting Request Oct 23rd or 24th- Pilot Flying J

Anne – November 2nd unfortunately does not work. Would you all be available for a call with Mandy either Tuesday, November 7th at 2:00PM or Friday, November 11th at 11:00AM EDT?

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Anne Steckel Personal Email / Ex. 6
Sent: Thursday, October 19, 2017 3:32 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: Meeting Request Oct 23rd or 24th- Pilot Flying J

Hi, Thanks for the email, Michael will be back Nov 2. Does that work?

Thanks much,
Anne

Sent from my iPhone

On Oct 19, 2017, at 2:53 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hi Anne,
>
> I apologize for the delayed response. Unfortunately I am booked both Monday and Tuesday next week. Is Michael going to be back in town in November? I'd be happy to hold a time to meet with him then.
>
> I'm looping in Alex to help with the logistics.
> Best,
> Mandy
>
> **From:** Anne Steckel Personal Email / Ex. 6
> **Sent:** Thursday, October 19, 2017 2:46 PM
> **To:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Meeting Request Oct 23rd or 24th- Pilot Flying J
>
> Hi Mandy,

Just wanted to circle back with you on this request. Would love to share some of the thoughts the blenders have on addressing the RFS with you next Monday or Tuesday.

Thanks

Anne

Anne Steckel

202.422.4002

From: Anne Steckel
Sent: Tuesday, October 17, 2017 10:10 PM
To: gunasekara.mandy@epa.gov
Subject: Meeting Request Oct 23rd or 24th- Pilot Flying J

Hi Mandy,

I hope this email finds you well. We met while I was working for the National Biodiesel Board to discuss the RFS.

I've left NBB and am now representing Pilot Flying J truck stops on renewable fuels issues.
Pilot Flying J is one of the largest distributors of renewable fuels and has a great interest in the RFS.
Pilot's head of renewable fuels, Michael Whitney, is going to be in DC next week, Oct 23 and 24th and would like to meet with you.

Do you have any availability on October 23 or 24?

Thanks in advance,

Anne

Anne Steckel
Ardent Strategies
202.422.4002

Appointment

Subject: Flight# UA9154 from CGN -> MUC (1 hour and 5 mins.) Layover of 1 hour and 30 mins. Flight# 107 from MUC -> IAD (9 hours and 25 mins.)

Start: 11/16/2017 8:35:00 AM
End: 11/16/2017 8:35:00 PM
Show Time As: Busy

Importance: High

Recurrence: (none)

Trip Overview
~~~~~~~~~~~~~

Trip Name: United Nations Framework Convention of Climate Change in Bonn, Germany
Start Date: November 11, 2017
End Date: November 16, 2017
Created: November 01, 2017, AMANDA GUNASEKARA (Modified: November 01, 2017)
Description: USEPA representative on United States delegation to the UNFCCC Conference.
Agency Record Locator: NWD7K2
Passengers: Amanda M Gunasekara
Total Estimated Cost: $ 2,405.36 USD
Important: Reservations must be approved and ticketed no later than: 11/09/2017 3:40 PM Eastern
The trip will be automatically cancelled if it is not approved before the deadline.
Agency Name: BCD_EPA

Reservations
~~~~~~~~~~~~
Saturday, November 11, 2017

Flight Washington, DC (IAD) to Munich (MUC)
```

United 106

This flight leaves on Nov 11 and arrives on Nov 12.

Departure: 05:40 PM
Seat: 40E (Confirmed)
Washington Dulles Intl (IAD)
Arrival: 07:40 AM
Munich Intl Arpt (MUC)
Confirmation: HY6D82
Status: Confirmed
Air Frequent Flyer Number: UA-RQV65054
Distance: 4249 miles
Emissions: 1657.1 lbs CO 2
Cabin: Economy (S)
Check passport, visa, and health requirements for this stop
Remarks
FOR UP TO DATE TRAVEL INFORMATION ON AIRLINE
CHECK-IN/RESTRICTIONS/LIMITATIONS/SECURITY.
PLEASE CHECK WWW.UAL.COM

Sunday, November 12, 2017
---

3 hr, 25 min layover at Munich Intl Arpt (MUC)

Flight Munich (MUC) to Cologne (CGN)
```

Lufthansa 1986

Departure: 11:05 AM
Seat: No seat assignment
Munich Intl Arpt (MUC)

Arrival: 12:10 PM
Koeln Bonn Arpt (CGN)
Confirmation: MCXBFI
Status: Confirmed
Distance: 271 miles
Emissions: 143.6 lbs CO 2
Cabin: Economy (Y)
Remarks
FOR UP TO DATE TRAVEL INFORMATION ON AIRLINE
CHECK-IN/RESTRICTIONS/LIMITATIONS/SECURITY.
PLEASE CHECK CMS.LUFTHANSA.COM

Thursday, November 16, 2017

Flight Cologne (CGN) to Munich (MUC)
```

United 9154
Operated by: DEUTSCHE LUFTHANSA AG

Departure: 09:35 AM
Seat: No seat assignment
Koeln Bonn Arpt (CGN)
Arrival: 10:40 AM
Munich Intl Arpt (MUC)
Confirmation: HY6D82
Status: Confirmed
Air Frequent Flyer Number: UA-RQV65054
Distance: 271 miles
Emissions: 143.6 lbs CO 2
Cabin: Economy (Y)

1 hr, 30 min layover at Munich Intl Arpt (MUC)

Flight Munich (MUC) to Washington, DC (IAD)
```

United 107

Departure: 12:10 PM
Seat: 44G (Confirmed)
Munich Intl Arpt (MUC)
Arrival: 03:35 PM
Washington Dulles Intl (IAD)
Confirmation: HY6D82
Status: Confirmed
Air Frequent Flyer Number: UA-RQV65054
Distance: 4249 miles
Emissions: 1657.1 lbs CO 2
Cabin: Economy (Y)

Total Estimated Cost
~~~~~~~~~~~~~~~~~~~~

Air
Airfare quoted amount: $ 2,234.00 USD
Taxes and fees: $ 171.36 USD
Total Estimated Cost: $ 2,405.36 USD

TICKET NOT YET ISSUED. AIRFARE QUOTED IN ITINERARY IS NOT GUARANTEED UNTIL TICKETS ARE ISSUED.
Remarks
~~~~~~~
FOR 24/7 TRAVEL ASSISTANCE PLEASE CONTACT
THE BCD TRAVEL TEAM AT 1-866-964-1346
FOR OUTSIDE THE US CALL COLLECT 770-829-2609
FOR THE HEARING IMPAIRED- PLEASE DIAL 711
TO ACCESS RELAY SERVICE- PROVIDE PHONE
NUMBER OF 1-866-964-1346 TO ACCESS TRAVEL
****
DUE TO RECENT CHANGES IN THE FY15 GOVERNMENT CITY PAIR
PROGRAM/CPP YOUR AIR RESERVATIONS ARE SUBJECT TO
CANCELLATION BY THE AIRLINES IF NOT TICKETED AT LEAST
48 HOURS PRIOR TO SCHEDULED DEPARTURE
PLEASE ENSURE ALL NECESSARY APPROVALS ARE PROCESSED IN
ACCORDANCE WITH YOUR AGENCYS BUSINESS RULES BUT NOLESS
THAN 3 BUSINESS DAYS PRIOR TO DEPARTURE TO ENSURE TICKETING.
THIS 48 HOUR CANCELLATION RULE DOES NOT APPLY TO

INTERNATIONAL RESERVATIONS UNLESS YOUR TRIP HAS DOMESTIC
CONNECTIONS ON MORE THAN ONE AIRLINE OR THESE
RESERVATIONS REQUIRE SEPARATE AIR TICKETS.
****
CHECK WWW.CDC.GOV/TRAVEL FOR TRAVEL HEALTH ADVISORIES
CHECK WWW.DHS.GOV/TRAVEL-ALERTS
FOR COUNTRY TRAVEL ADVISORIES
PROPER DOCUMENTATION IS REQUIRED FOR ENTRY INTO
ARRIVAL COUNTRY

M&K TRUCK CENTERS
ILLINOIS | INDIANA | MICHIGAN

October 18, 2017

The Honorable Scott Pruitt
Administrator
Environmental Protection Agency
1200 Pennsylvania Ave NW
Washington, DC 20460

Cc: Mandy Gunasekara, Senior Advisor to the Administrator (by email) Gunasekara.Mandy@epa.gov
Erik Baptist, Senior Deputy General Counsel (by email) Baptist.erik@epa.gov

I am a private business owner with operations in Byron Center, MI, Holland, MI, Wyoming, MI, Kalamazoo, MI, Romulus, MI, Sterling Heights, MI, Frankfort, IN, Indianapolis, IN, Kokomo, IN, Wilkes-Barre, PA, Alsip, IL, Des Plaines, IL, Summit, IL, Joliet, IL and Columbus, MS. I ask you to keep the volume cap on "glider vehicles" as written in the final Greenhouse Gas Phase 2 regulation.

Simply, glider vehicles are sold against us but with an unfair competitive advantage.

Today's new trucks meet US '10 emission levels by the installation of an expensive "chemical factory" behind the engine (the SCR and DPF). Because gliders vehicles don't meet the current emission standards, they avoid these expensive "chemical factories" that we, as conscientious business owners complying with EPA's strict emissions standards, provide our customers with the least amount of emissions possible.

Also, we are required to pay a 12% Federal excise tax on the sales price for every truck we sell. Glider Vehicles may not have to pay the excise tax. This tax is used to fund the Federal highway trust fund which helps pay for our roads and bridges. So, we are at a 12% unfair price disadvantage and the vehicles we sell to build highway infrastructure is impacted as the fund is lessened with every glider vehicle sold.

I have lost sales to competitors that are selling 500 untaxed trucks with dirty engines and often the customers are told that the FET isn't due when it is. I simply want a level playing field so that we can fairly compete.

Please feel free to contact me at ron.meyering@mktruck.com

Ron Meyering
President
M&K Truck Center

EPA-HQ-2018-002296

CSAPR NO_X Ozone Season Group 2 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.808 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the CSAPR NO_X Ozone Season Group 2 Trading Program are set forth in part 78 of this chapter.

§ 97.809 [Reserved]

§ 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) The State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 2 allowances for the control periods in 2017 and thereafter are as follows:

(1) *Alabama.* (i) The NO_X Ozone Season Group 2 trading budget is 13,211 tons.

(ii) The new unit set-aside is 255 tons.

(iii) The Indian country new unit set-aside is 13 tons.

(2) *Arkansas.* (i) The NO_X Ozone Season Group 2 trading budget for 2017 is 12,048 tons and for 2018 and thereafter is 9,210 tons.

(ii) The new unit set-aside for 2017 is 240 tons and for 2018 and thereafter is 185 tons.

(iii) [Reserved]

(3) *Georgia.* (i) The NO_X Ozone Season Group 2 trading budget is 8,481 tons.

(ii) The new unit set-aside is 168 tons.

(iii) [Reserved]

(4) *Illinois.* (i) The NO_X Ozone Season Group 2 trading budget is 14,601 tons.

(ii) The new unit set-aside is 302 tons.

(iii) [Reserved]

(5) *Indiana.* (i) The NO_X Ozone Season Group 2 trading budget is 23,303 tons.

(ii) The new unit set-aside is 468 tons.

(iii) [Reserved]

(6) *Iowa.* (i) The NO_X Ozone Season Group 2 trading budget is 11,272 tons.

(ii) The new unit set-aside is 324 tons.

(iii) The Indian country new unit set-aside is 11 tons.

(7) *Kansas.* (i) The NO_X Ozone Season Group 2 trading budget is 8,027 tons.

(ii) The new unit set-aside is 148 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(8) *Kentucky.* (i) The NO_X Ozone Season Group 2 trading budget is 21,115 tons.

(ii) The new unit set-aside is 426 tons.

(iii) [Reserved]

(9) *Louisiana.* (i) The NO_X Ozone Season Group 2 trading budget is 18,639 tons.

(ii) The new unit set-aside is 352 tons.

(iii) The Indian country new unit set-aside is 19 tons.

(10) *Maryland.* (i) The NO_X Ozone Season Group 2 trading budget is 3,828 tons.

(ii) The new unit set-aside is 152 tons.

(iii) [Reserved]

(11) *Michigan.* (i) The NO_X Ozone Season Group 2 trading budget is 17,023 tons.

(ii) The new unit set-aside is 665 tons.

(iii) The Indian country new unit set-aside is 17 tons.

(12) *Mississippi.* (i) The NO_X Ozone Season Group 2 trading budget is 6,315 tons.

(ii) The new unit set-aside is 120 tons.

(iii) The Indian country new unit set-aside is 6 tons.

(13) *Missouri.* (i) The NO_X Ozone Season Group 2 trading budget is 15,780 tons.

(ii) The new unit set-aside is 324 tons.

(iii) [Reserved]

(14) *New Jersey.* (i) The NO_X Ozone Season Group 2 trading budget is 2,062 tons.

(ii) The new unit set-aside is 192 tons.

(iii) [Reserved]

(15) *New York.* (i) The NO_X Ozone Season Group 2 trading budget is 5,135 tons.

(ii) The new unit set-aside is 252 tons.

(iii) The Indian country new unit set-aside is 5 tons.

(16) *Ohio.* (i) The NO_X Ozone Season Group 2 trading budget is 19,522 tons.

(ii) The new unit set-aside is 401 tons.

(iii) [Reserved]

(17) *Oklahoma.* (i) The NO_X Ozone Season Group 2 trading budget is 11,641 tons.

(ii) The new unit set-aside is 221 tons.

(iii) The Indian country new unit set-aside is 12 tons.

(18) *Pennsylvania.* (i) The NO_X Ozone Season Group 2 trading budget is 17,952 tons.

(ii) The new unit set-aside is 541 tons.

(iii) [Reserved]

(19) *Tennessee.* (i) The NO_X Ozone Season Group 2 trading budget is 7,736 tons.

(ii) The new unit set-aside is 156 tons.

(iii) [Reserved]

(20) *Texas.* (i) The NO_X Ozone Season Group 2 trading budget is 52,301 tons.

(ii) The new unit set-aside is 998 tons.

(iii) The Indian country new unit set-aside is 52 tons.

(21) *Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 9,223 tons.

(ii) The new unit set-aside is 562 tons.

(iii) [Reserved]

(22) *West Virginia.* (i) The NO_X Ozone Season Group 2 trading budget is 17,815 tons.

(ii) The new unit set-aside is 356 tons.

(iii) [Reserved]

(23) *Wisconsin.* (i) The NO_X Ozone Season Group 2 trading budget is 7,915 tons.

(ii) The new unit set-aside is 151 tons.

(iii) The Indian country new unit set-aside is 8 tons.

(b) The States' variability limits for the State NO_X Ozone Season Group 2 trading budgets for the control periods in 2017 and thereafter are as follows:

(1) The variability limit for Alabama is 2,774 tons.

(2) The variability limit for Arkansas for 2017 is 2,530 tons and for 2018 and thereafter is 1,934 tons.

(3) The variability limit for Georgia is 1,781 tons.

(4) The variability limit for Illinois is 3,066 tons.

(5) The variability limit for Indiana is 4,894 tons.

(6) The variability limit for Iowa is 2,367 tons.

(7) The variability limit for Kansas is 1,686 tons.

(8) The variability limit for Kentucky is 4,434 tons.

(9) The variability limit for Louisiana is 3,914 tons.

(10) The variability limit for Maryland is 804 tons.

(11) The variability limit for Michigan is 3,575 tons.

(12) The variability limit for Mississippi is 1,326 tons.

(13) The variability limit for Missouri is 3,314 tons.

(14) The variability limit for New Jersey is 433 tons.

(15) The variability limit for New York is 1,078 tons.

(16) The variability limit for Ohio is 4,100 tons.

(17) The variability limit for Oklahoma is 2,445 tons.

(18) The variability limit for Pennsylvania is 3,770 tons.

(19) The variability limit for Tennessee is 1,625 tons.

(20) The variability limit for Texas is 10,983 tons.

(21) The variability limit for Virginia is 1,937 tons.

(22) The variability limit for West Virginia is 3,741 tons.

(23) The variability limit for Wisconsin is 1,662 tons.

(c) Each State NO_X Ozone Season Group 2 trading budget in this section includes any tons in a new unit set-aside or Indian country new unit set-aside but does not include any tons in a variability limit.

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

(a) *Existing units.* (1) CSAPR NO_X Ozone Season Group 2 allowances are

ED_002110_00030380-00001

Facility	State	ORIS	Boiler	CAMD ID	Unit Type	2016 Heat Input (mmBtu)	2016 Gross Generation (mWh)	2016 Capacity Factor (%)	2016 NOx (tons)	2016 NOx Rate Ozone Season (lbs/MMBtu)	2023 NOx (tons)	2023 NOx Rate Ozone Season (lbs/MMBtu)	Adjusted from 2016	Reason for Adjustment
Big Sandy	Kentucky	1353	BSU1	872	Dry bottom wall-fired boiler	3,608,992	350,415	39%	277	0.154	277	0.154		
Bluegrass Generating Station	Kentucky	55164	GTG1	4034	Combustion turbine	66,848	5,842	1%	2	0.051	2	0.051		
Bluegrass Generating Station	Kentucky	55164	GTG2	4035	Combustion turbine	49,310	4,352	1%	2	0.069	2	0.069		
Bluegrass Generating Station	Kentucky	55164	GTG3	8446	Combustion turbine	224,918	19,683	3%	7	0.061	7	0.061		
Cane Run	Kentucky	1363	7A	90928	Combined cycle	7,184,719	1,116,320	82%	94	0.026	94	0.026		
Cane Run	Kentucky	1363	7B	90929	Combined cycle	7,225,490	1,127,979	82%	85	0.023	85	0.023		
Coleman	Kentucky	1381	C1	926	Dry bottom wall-fired boiler									
Coleman	Kentucky	1381	C2	927	Dry bottom wall-fired boiler									
Coleman	Kentucky	1381	C3	928	Dry bottom wall-fired boiler									
D B Wilson	Kentucky	6823	W1	2910	Dry bottom wall-fired boiler	15,606,933	1,419,774	70%	470	0.060	470	0.060		
E W Brown	Kentucky	1355	1	874	Dry bottom wall-fired boiler	1,608,320	149,804	32%	172	0.214	172	0.214		
E W Brown	Kentucky	1355	10	875	Combustion turbine	484,560	37,797	8%	30	0.123	30	0.123		
E W Brown	Kentucky	1355	11	876	Combustion turbine	514,763	37,858	9%	29	0.113	29	0.113		
E W Brown	Kentucky	1355	2	877	Tangentially-fired	2,819,752	262,569	37%	299	0.212	299	0.212		
E W Brown	Kentucky	1355	3	878	Tangentially-fired	8,123,757	751,399	44%	616	0.152	406	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
E W Brown	Kentucky	1355	5	879	Combustion turbine	225,019	17,592	4%	6	0.053	6	0.053		
E W Brown	Kentucky	1355	6	880	Combustion turbine	164,620	14,417	2%	4	0.051	4	0.051		
E W Brown	Kentucky	1355	7	881	Combustion turbine	155,197	13,678	2%	6	0.071	6	0.071		
E W Brown	Kentucky	1355	8	882	Combustion turbine	680,793	53,181	12%	34	0.101	34	0.101		
E W Brown	Kentucky	1355	9	883	Combustion turbine	678,081	51,943	11%	43	0.126	43	0.126		
East Bend	Kentucky	6018	2	2682	Dry bottom wall-fired boiler	19,601,319	1,872,619	68%	1,163	0.119	980	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
Elmer Smith	Kentucky	1374	1	911	Cyclone boiler	3,180,174	338,480	16%	391	0.246	0	0.000	Y	Retiring
Elmer Smith	Kentucky	1374	2	912	Tangentially-fired	5,843,396	627,140	25%	999	0.342	0	0.000	Y	Retiring
Ghent	Kentucky	1356	1	884	Tangentially-fired	14,493,307	1,510,102	72%	464	0.064	464	0.064		
Ghent	Kentucky	1356	2	885	Tangentially-fired	12,577,886	1,443,234	59%	1,237	0.197	1,237	0.197		
Ghent	Kentucky	1356	3	886	Dry bottom wall-fired boiler	12,110,380	1,390,969	57%	1,004	0.166	606	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
Ghent	Kentucky	1356	4	887	Dry bottom wall-fired boiler	14,109,599	1,515,538	70%	798	0.113	705	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
H L Spurlock	Kentucky	6041	1	2704	Dry bottom wall-fired boiler	9,470,360	967,229	71%	416	0.088	416	0.088		
H L Spurlock	Kentucky	6041	2	2705	Tangentially-fired	14,966,642	1,583,051	65%	685	0.092	685	0.092		
H L Spurlock	Kentucky	6041	3	89571	Circulating fluidized bed boiler	6,620,188	742,306	58%	200	0.060	200	0.060		
H L Spurlock	Kentucky	6041	4	90241	Circulating fluidized bed boiler	9,064,195	1,043,926	88%	258	0.057	258	0.057		
HMP&L Station 2	Kentucky	1382	H1	929	Dry bottom wall-fired boiler	2,696,002	283,894	37%	284	0.211	135	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
HMP&L Station 2	Kentucky	1382	H2	930	Dry bottom wall-fired boiler	4,984,770	473,181	68%	366	0.147	249	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
John S. Cooper	Kentucky	1384	1	932	Dry bottom wall-fired boiler	1,261,867	126,351	25%	128	0.203	98	0.155	Y	Install State-of-the-art combustion controls
John S. Cooper	Kentucky	1384	2	933	Dry bottom wall-fired boiler	2,396,111	244,608	27%	129	0.108	120	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
Marshall	Kentucky	55232	CT1	4240	Combustion turbine	123,058	10,060	3%	1	0.022	1	0.022		
Marshall	Kentucky	55232	CT2	4241	Combustion turbine	129,278	10,540	3%	1	0.023	1	0.023		
Marshall	Kentucky	55232	CT3	4242	Combustion turbine	130,998	10,834	3%	2	0.025	2	0.025		
Marshall	Kentucky	55232	CT4	4243	Combustion turbine	114,605	9,223	3%	1	0.021	1	0.021		
Marshall	Kentucky	55232	CT5	4244	Combustion turbine	139,523	11,586	3%	1	0.021	1	0.021		
Marshall	Kentucky	55232	CT6	4245	Combustion turbine	132,342	10,888	3%	2	0.024	2	0.024		
Marshall	Kentucky	55232	CT7	4246	Combustion turbine	97,210	7,777	2%	1	0.024	1	0.024		
Marshall	Kentucky	55232	CT8	4247	Combustion turbine	84,407	6,874	2%	1	0.024	1	0.024		
Mill Creek	Kentucky	1364	1	905	Tangentially-fired	7,492,803	844,362	55%	1,141	0.305	521	0.139	Y	Install State-of-the-art combustion controls
Mill Creek	Kentucky	1364	2	906	Tangentially-fired	7,523,529	849,227	55%	1,147	0.305	523	0.139	Y	Install State-of-the-art combustion controls
Mill Creek	Kentucky	1364	3	907	Dry bottom wall-fired boiler	9,009,428	952,039	56%	265	0.059	265	0.059		
Mill Creek	Kentucky	1364	4	908	Dry bottom wall-fired boiler	12,734,811	1,339,159	63%	299	0.047	299	0.047		
Paddy's Run	Kentucky	1366	12	10010	Combustion turbine	9,636		1%	3	0.700	3	0.700		
Paddy's Run	Kentucky	1366	13	909	Combustion turbine	757,079	86,990	11%	29	0.076	29	0.076		
Paducah Power Systems Plant 1	Kentucky	56556	EU01A	90590	Combustion turbine	79,759	7,254	7%	20	0.497	20	0.497		
Paducah Power Systems Plant 1	Kentucky	56556	EU01B	90591	Combustion turbine	82,798	7,474	7%	18	0.441	18	0.441		
Paducah Power Systems Plant 1	Kentucky	56556	EU02A	90592	Combustion turbine	81,122	7,278	7%	12	0.304	12	0.304		
Paducah Power Systems Plant 1	Kentucky	56556	EU02B	90593	Combustion turbine	88,366	7,876	7%	17	0.376	17	0.376		
Paradise	Kentucky	1378	1	913	Cyclone boiler	13,321,673	1,242,995	39%	803	0.121	0	0.000	Y	Retiring
Paradise	Kentucky	1378	2	914	Cyclone boiler	17,111,166	1,532,616	58%	1,029	0.120	0	0.000	Y	Retiring
Paradise	Kentucky	1378	3	915	Cyclone boiler	20,552,854	2,001,152	38%	1,933	0.188	1,028	0.100	Y	Optimize SCR to 0.10 lb/mmBtu
Paradise	Kentucky	1378	PCC1	91045										
Paradise	Kentucky	1378	PCC2	91046										
Paradise	Kentucky	1378	PCC3	91047										
R D Green	Kentucky	6639	G1	2896	Dry bottom wall-fired boiler	6,690,947	644,666	65%	758	0.226	758	0.226		
R D Green	Kentucky	6639	G2	2897	Dry bottom wall-fired boiler	6,812,704	636,212	66%	852	0.250	852	0.250		
Riverside Generating Company	Kentucky	55198	GTG101	4105	Combustion turbine	667,229	59,527	9%	17	0.052	17	0.052		
Riverside Generating Company	Kentucky	55198	GTG201	4106	Combustion turbine	963,879	88,203	12%	26	0.054	26	0.054		
Riverside Generating Company	Kentucky	55198	GTG301	4107	Combustion turbine	935,978	84,318	12%	26	0.056	26	0.056		
Riverside Generating Company	Kentucky	55198	GTG401	4108	Combustion turbine	962,181	86,321	12%	30	0.061	30	0.061		
Riverside Generating Company	Kentucky	55198	GTG501	4109	Combustion turbine	950,015	85,286	12%	27	0.057	27	0.057		
Robert Reid	Kentucky	1383	R1	931	Dry bottom wall-fired boiler									
Robert Reid	Kentucky	1383	RT	88132	Combustion turbine	54,726	3,106	2%	19	0.700	19	0.700		
Shawnee	Kentucky	1379	1	916	Dry bottom wall-fired boiler	3,160,750	285,431	40%	502	0.318	119	0.075	Y	New SCR
Shawnee	Kentucky	1379	2	918	Dry bottom wall-fired boiler	4,436,768	396,895	52%	700	0.316	700	0.316		

Facility	State	ORIS	Boiler	CAMD ID	Unit Type	2016 Heat Input (mmBtu)	2016 Gross Generation (mWh)	2016 Capacity Factor (%)	2016 NOx (tons)	2016 NOx Rate Ozone Season (lbs/MMBtu)	2023 NOx (tons)	2023 NOx Rate Ozone Season (lbs/MMBtu)	Adjusted from 2016	Reason for Adjustment
Shawnee	Kentucky	1379	3	919	Dry bottom wall-fired boiler	4,226,670	377,571	50%	667	0.316	667	0.316		
Shawnee	Kentucky	1379	4	920	Dry bottom wall-fired boiler	4,449,382	398,654	57%	701	0.315	167	0.075	Y	New SCR
Shawnee	Kentucky	1379	5	921	Dry bottom wall-fired boiler	4,542,983	406,790	54%	720	0.317	352	0.155	Y	Install State-of-the-art combustion controls
Shawnee	Kentucky	1379	6	922	Dry bottom wall-fired boiler	4,188,222	390,480	58%	523	0.250	324	0.155	Y	Install State-of-the-art combustion controls
Shawnee	Kentucky	1379	7	923	Dry bottom wall-fired boiler	3,918,024	364,979	41%	484	0.247	303	0.155	Y	Install State-of-the-art combustion controls
Shawnee	Kentucky	1379	8	924	Dry bottom wall-fired boiler	4,095,173	382,102	42%	511	0.249	317	0.155	Y	Install State-of-the-art combustion controls
Shawnee	Kentucky	1379	9	925	Dry bottom wall-fired boiler	3,294,504	308,462	32%	416	0.252	255	0.155	Y	Install State-of-the-art combustion controls
Smith Generating Facility	Kentucky	54	SCT1	50	Combustion turbine	100,593	7,489	2%	2	0.049	2	0.049		
Smith Generating Facility	Kentucky	54	SCT10	90542	Combustion turbine	166,584	16,502	5%	1	0.012	1	0.012		
Smith Generating Facility	Kentucky	54	SCT2	51	Combustion turbine	124,574	8,856	2%	4	0.060	4	0.060		
Smith Generating Facility	Kentucky	54	SCT3	52	Combustion turbine	88,609	6,750	1%	3	0.064	3	0.064		
Smith Generating Facility	Kentucky	54	SCT4	9271	Combustion turbine	222,679	16,404	5%	3	0.028	3	0.028		
Smith Generating Facility	Kentucky	54	SCT5	9272	Combustion turbine	211,576	15,916	4%	3	0.030	3	0.030		
Smith Generating Facility	Kentucky	54	SCT6	89572	Combustion turbine	201,654	14,943	4%	3	0.027	3	0.027		
Smith Generating Facility	Kentucky	54	SCT7	89573	Combustion turbine	193,535	14,517	4%	3	0.027	3	0.027		
Smith Generating Facility	Kentucky	54	SCT9	90541	Combustion turbine	156,390	15,575	4%	1	0.013	1	0.013		
Trimble County	Kentucky	6071	1	2737	Tangentially-fired	15,521,427	1,677,613	70%	666	0.086	666	0.086		
Trimble County	Kentucky	6071	10	2738	Combustion turbine	730,130	63,601	10%	10	0.027	10	0.027		
Trimble County	Kentucky	6071	2	90433	Dry bottom wall-fired boiler	12,168,215	1,389,437	44%	244	0.040	244	0.040		
Trimble County	Kentucky	6071	5	2739	Combustion turbine	757,293	65,925	10%	13	0.034	13	0.034		
Trimble County	Kentucky	6071	6	2740	Combustion turbine	522,756	45,331	7%	8	0.032	8	0.032		
Trimble County	Kentucky	6071	7	2741	Combustion turbine	870,014	76,104	12%	14	0.033	14	0.033		
Trimble County	Kentucky	6071	8	2742	Combustion turbine	169,113	14,786	2%	2	0.026	2	0.026		
Trimble County	Kentucky	6071	9	2743	Combustion turbine	1,060,108	93,218	14%	17	0.032	17	0.032		
William C. Dale	Kentucky	1385	3	934	Dry bottom wall-fired boiler						0		Y	Retiring
William C. Dale	Kentucky	1385	4	935	Dry bottom wall-fired boiler						0		Y	Retiring
Paradise	Kentucky	1378	CC1		Combined Cycle						87		Y	New Unit > 25MW

GATR TRUCK CENTER

October 13, 2017

The Honorable Scott Pruitt
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

Cc: Mandy Gunasekara, Senior Advisor to the Administrator (by email) Gunasekara.Mandy@epa.gov
Erik Baptist, Senior Deputy General Counsel (by email) baptist.erik@epa.gov

I am a private business owner with operations in Sauk Rapids, MN, Elk River, MN, Des Moines, IA, Cedar Rapids, IA, and Waterloo, IA, that employs 275 people. In order for our business to be successful, and keep these people employed, we must be competitive in selling heavy duty trucks. I ask you to keep the volume cap on "glider vehicles" as written in the final Greenhouse Gas Phase 2 regulation.

Simply, glider vehicles are sold against us but with an unfair competitive advantage.

Today's new trucks meet US '10 emission levels by the installation of an expensive "chemical factory" behind the engine (the SCR and DPF). Because gliders vehicles don't meet the current emission standards, they avoid these expensive "chemical factories" that we, as conscientious business owners complying with EPA's strict emissions standards, provide our customers with the least amount of emissions possible.

Also, we are required to pay a 12% Federal excise tax on the sales price for every truck we sell. Glider Vehicles may not have to pay the excise tax. This tax is used to fund the Federal highway trust fund which helps pay for our roads and bridges. So, we are at a 12% unfair price disadvantage and the vehicles we sell to build highway infrastructure is impacted as the fund is lessened with every glider vehicle sold.

I have lost sales to glider vehicles and it negatively impacts my business. I simply want a level playing field so that we can fairly compete.

Please feel free to contact me at bneitzke@gatr.net.

Sincerely,

Robert A. Neitzke
CEO

218 Stearns Drive
Sauk Rapids, MN 56379
P: 320-251-7356

10743 168th Circle NW
Elk River, MN 55330
P: 763-441-2205

700 29th Ave. SW
Cedar Rapids, IA 52404
P: 319-298-1000

5325 NE 14th Street
Des Moines, IA 50313
P: 515-263-3600

955 West Airline Hwy
Waterloo, IA 50703
P: 319-233-6741

1-800-771-GATR www.gatr.net

Message

From: Hawk Personal Email / Ex. 6
Sent: 10/17/2017 3:27:49 PM
To: elizabeth_horner@epw.senate.gov
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Fwd: Mandy Gunasekara

Hello Ms. Horner,
I am going to be on the Hill Thursday (10/19) may I swing by at 3:30 pm?
Thank you,
Hawk

Begin forwarded message:

From: Angelique Hawk Personal Email / Ex. 6
Subject: Mandy Gunasekara
Date: October 13, 2017 at 1:16:51 PM EDT
To: elizabeth_horner@epw.senate.gov

Hello Ms. Horner,

On two separate occasions this week it was suggested I should meet you. Mandy Gunasekara and I were out for coffee and she spoke highly of you. She suggested that you might have some helpful insight to share. Mary Martin mentioned to me the other day I should meet you too.

Personal Matters / Ex. 6

Would you have time to speak to me over a cup of coffee or drink in the following weeks?

Thank you,

Hawk

Message

From: Agile Development & Contracting Workshop [PotomacForum@AgileInGovWorkshop.org]
Sent: 10/16/2017 6:06:28 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: [SPAM] Latest in Agile Development & Contracting-Practical Information

Outstanding Government Speakers - Agile Development & Contracting
- Please Forward to Others in Your Organization Interested in Agile Development for Software Development, Contracting or Other Applications

---

Agile Development in Government Training Workshop IX:

Laying the Right Foundation for Agility Within Your Agency

What Executives, Managers and Staff Need to Know
A "How to" Workshop Discussing Best Practices and Lessons Learned

Wednesday, November 8, 2017

Willard InterContinental Hotel
Washington, D.C.

Link to Potomac Forum Website: www.PotomacForum.org

Government & Industry Invited to Attend

Sponsored by:
Potomac Forum, Ltd
providing training to government since 1982

Previous Eight Agile Workshops
Rated As Excellent By
Government & Industry Students

Potomac Forum Workshops are 100% Training and Not Sales or Marketing Events

Government Speakers:

Keynote
William (Bill) Pratt
Director, IT Standards & Program Support
Office of the CIO
Department of Homeland Security
(awaiting agency approval)
(Author of the Widely Acclaimed DHS AGILE Guidebook Used by DHS and Many Other Government Agencies)

Featured Speaker
Jonathan Mostowski
Member of the Defense Digital Service Team, The White House and Pentagon

---

Tia Norman
Branch Chief - Agile Maturity & Governance
Office of the CIO
Department of Homeland Security
(awaiting agency approval)

Melissa Cohen
Director, Policy and Programs Group
Center for Medicare Medicaid Services (CMS)

Daniel Levenson
Digital Service Contracting Advisor
Center for Medicare & Medicaid Services (CMS)

Additional Government Speakers to be Announced Soon

With the current Administration's emphasis on IT Modernization coupled with today's demanding environment and reduced budgets, most Federal agencies are at some level of Agile adoption or transformation to increase efficiencies and meet these challenging demands. However, many would welcome insight into how best to address the cultural issues and other factors contributing to impediments to Agile adoption. Knowing how to achieve success in this process by laying the right foundation will be the key focus of this workshop.

Overview of the Workshop:
Agile Development in Government Training Workshop IX: Laying the Right Foundation for Agility Within Your Agency is designed to provide attendees with practical suggestions from other government agencies to address the kinds of challenges to prepare for based on their own experiences with Agile transition approaches that have worked for them; "laying the right foundation". The afternoon government panel will also share their insights on lessons learned based on their real-world experiences as they navigate through their Agile transformation within their own agencies.

What You Will Learn:

- **What typically drives the pockets of resistance in government agencies and how can they be dealt with successfully?**
- **How will my role and responsibilities change, and how can I best prepare myself?**
- **How can we ensure that our contracting for Agile Digital Services is not in conflict with the FAR?**
- **What are some innovative contracting initiatives that are already working for government?**
- **We've already started down the path of Agile adoption. What are some of the commercial best practices that we could adopt in our government agency?**
- **What should we know about selecting and interacting with Agile partners from industry?**
- **What kind of training should my government staff be looking for to best manage the government/vendor relationship on my Agile projects?**

Why You Should Attend:

- As more and more government agencies move to adopt Lean and Agile practices, there must be assurance that they are keeping within the regulatory boundaries unique to the Federal government. Many agencies are already doing this very successfully. This workshop will show you how they are navigating these challenges.

- There are agencies that are eliminating costly mistakes and downtime by successfully adopting Lean and Agile practices. Come and hear their experiences and lessons learned.

- Agile practices not only take technical expertise, but require deep cultural change. Hear from experts and daily practitioners about the

importance of managing these cultural challenges and how they are successfully driving cultural change based on their real world experiences.

Who Should Attend:

- **CIOs, CTOs, Federal IT experts**
- **Contracting officers Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their Agencies**
- **Acquisition professionals**
- **Agencies new to adopting Agile projects**
- **Agencies that have already started to adopt Agile practices who want to move to the next level of agility**
  Development and Operations teams facing ongoing challenges to deployment
- **Program and project managers**
- **Agile teams facing ongoing challenges to acquisition**
- **Chief Financial Officers and Staff**
- **Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their agencies**
- **Project and program managers who want to better understand their role in an Agile environment**
- **Inspector Generals and Staff**
- **Industry Executives, Managers and Staff who support the government**

Workshop for Government and Industry Partners
Press is NOT Permitted to Permit Candid Discussion

CEUs and CLUs Credits
Awarded for Attendance

Team "Learn Together" Reduced Registration Fee

Student Evaluation Comments from Previous Potomac Forum
Agile in Government Training Workshops

I was extremely pleased and will consider Potomac Forum for future raining needs
Lead Contact Specialist
Independent Agency

This workshop was extremely beneficial. I knew very little about the Agile method prior to this workshop and now feel like I can talk about Agile effectively
Investigator
DOJ Agency

The overall workshop was excellent. I have a pretty good understanding of Agile and feel that I'm ready to start a small Agile project
IT Systems Division Chief
DOJ Agency

The workshop as excellent and very informative.
Excellent training session
Branch Chief
Federal Agency

Timely topics, engaging & knowledgeable speakers, good flow, well organized
Business Process Improvement Specialist
Business Process Improvement Specialist
Independent Agency

Educational, informative, enjoyable! Exactly what I wanted
Excellent speakers
Sr Project Manager
Large Government Contractor

Informative and educational. Good examples of implementation and/or risks.
Panel Discussion very beneficial
Sr Projects Officer
Government Agency

It was an excellent gathering with experts and we got to benefit from their experience in real projects
IT Specialist
Independent Agency

Workshop for Government and Industry Partners

Learn Together Team Rates:
Reduced Registration for Multiple Attendees from the same organization

Registration and Information:
www.potomacforum.org

Call: (703) 683-1613
info@PotomacForum.org

Sponsored by:
Potomac Forum, Ltd.
Founded in 1982 as a non-profit educational organization

Potomac Forum, Ltd is Proud to be:
Corporate Partner of
The Association of Government Accountants

Sustaining Partner
Association for Federal Information Resources Management
AFFIRM

Potomac Forum Direct Phone: (703) 683-1613

If this email is not of specific interest to you,
please forward to an associate.

Please DO NOT UNSUBSCRIBE from this
"Agile Development" mailing list.
Potomac Forum offers a wide variety of government related training events
which may be of interest to you in the future.
If you unsubscribe from this "Agile Development" list, you will
not receive future notices for "Agile Development" from this list.

Thank You.

This email was sent to: gunasekara.amanda@epa.gov

Go here to leave this mailing list or modify your email profile.
We respect your right to privacy. View our policy.

Potomac Forum, Ltd.

This email was sent by: **Potomac Forum, Ltd.**
400 North Washington Street , Alexandria , Virginia, 22314 , USA

Message

From: Hilary Moffett [moffetth@api.org]
Sent: 10/19/2017 1:43:21 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Methane Voluntary Program

Hi Mandy and Alex,

I hope this finds you well. In the past, API mentioned the voluntary efforts our companies are engaged in to lower methane emissions. We are working to launch a more formal API Voluntary Program early next year and would like the chance to come in and discuss the program particulars. Right now, our members are reviewing the program requirements and must make a decision about sign on by the first week of November. Are you guys available during the second week of November to chat about the voluntary efforts by industry and how this program, in conjunction with EPA efforts on the NSPS reconsideration, can result in some marked reductions in methane emissions.

Let me know if you have some time the second week in November.

Thank you for your consideration.

Regards,
Hilary

Message

From: Paul Bailey [pbailey@americaspower.org]
Sent: 10/28/2017 6:01:37 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: ACCCE Board mtg

Mandy –
Bonn should be very interesting. I would really appreciate suggestions, especially anyone as knowledgeable as you.
Thanks,
Paul

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Saturday, October 28, 2017 1:15 PM
To: Paul Bailey <pbailey@americaspower.org>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: ACCCE Board mtg

Hey Paul – Great to hear from you! I hope all is well. I'm going to the COP in Bonn, Germany (Nov. 11 through 16) so I won't be in town for the 15th. Would you like me to check with some of our other team members who may be available to speak to the board and provide a similar type overview? Just let me know and I can help facilitate.
In addition, please keep me on the list for future opportunities.
Best,
Mandy

From: Paul Bailey [mailto:pbailey@americaspower.org]
Sent: Friday, October 27, 2017 8:08 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: ACCCE Board mtg

Mandy –
Hope all is well. I'd like to invite you to speak at our Board meeting on November 15. Obviously, EPA policies are important to the coal fleet, so an update would be well received. We expect the meeting to start at 9:30 am and end at roughly noon, although the times could change slightly. Let me know if you're available, and we can talk further.
Paul
703-586-2422

Paul Bailey
President & CEO
American Coalition for Clean Coal Electricity
T: 202.459.4818 | **M**: 703.586.2422
pbailey@americaspower.org

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/18/2017 7:18:10 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting today
Attachments: Regional Haze Summary 10-18-17.docx

Our call with Justin went well! Sorry for any confusion this morning. I'm attaching a copy of a one-pager for you to reference for your meeting later today with Becky.

Thanks!

Stuart

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Wednesday, October 18, 2017 9:51 AM
To: Wagner, Kenneth
Cc: Spencer, Stuart; Dominguez, Alexander
Subject: Meeting today

Hi Ken, can you send me the logistical info for the meeting with Arkansas today? Also need call in info for Stuart (CC'd).

Sent from my iPhone

Recent activity re: Regional Haze SIP development and litigation

1. **NOX CSAPR SIP**:
    a. Allows Arkansas subject-to-BART electric generating units to comply with Regional Haze Rule via participation in CSAPR
    b. At ADEQ's request, EPA proposed to approve the NOX CSAPR SIP via parallel processing.
    c. Comment period for CSAPR SIP closed on August 14, 2017.
    d. Comment period on the EPA proposal to approve the NOX CSAPR SIP closed week of 10-9-17.
    e. ADEQ has completed response to comments document and is prepared to submit final doc to EPA.
    f. Sending Gov's letter to liaison today (10-18) and will be submitting SIP to EPA Region 6 by week's end or early next week.
    g. EPA Region 6 has indicated they will finalize their approval after ADEQ finalization (within next month-best guess).
2. **Remaining SIP components (SO2 BART, reasonable progress analysis, long term strategy, Domtar, etc.)**:
    a. ADEQ has shared drafts of the Phase II SIP and associated documents (administrative orders and technical analyses) with EPA HQ and EPA Region 6.
    b. EPA Region 6 technical and legal staff met with ADEQ staff at ADEQ HQ on 10-16 and 10-17 to review SIP and associated docs.
    c. ADEQ is finalizing a draft Phase II SIP revision based on Region 6's input.
    d. In the Phase II SIP, ADEQ is proposing the following BART requirements for subject-to-BART units:
        i. SO2 and PM BART determinations for AECC Bailey Plant Unit 1;
        ii. SO2 and PM BART determinations for AECC McClellan Plant Unit 1;
        iii. SO2 BART determinations for AEP SWEPCO Flint Creek Plant Boiler No. 1;
        iv. SO2 and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;
        v. *SO2 and PM BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2*;
        vi. SO2 and PM BART determinations for Entergy White Bluff Plant Auxiliary Boiler;
        vii. SO2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 1; and
        viii. *SO2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 2.*
    e. Of interest, BART for SO2 at White Bluff Units 1 and 2 is low sulfur coal and an emissions rate of 0.6 lbs/mmbtu, with contemplation of change in coal operations (remaining useful life).
    f. Analyzing possible reasonable progress control for Independence Units 1 and 2- low sulfur coal and an emissions rate of 0.6 lbs/mmbtu.
    g. AOs have been sent to affected facilities for consideration.
3. **Litigation**:
    a. Met with AG on 10-17-17 re: proposed Settlement Agreement.
    b. Provided edits to AG; AG calling DOJ today re: requested revisions.
4. **Asks**:
    a. Administrative stay (APA)
    b. Judicial stay
    c. Parallel processing of proposed Phase II SIP

Message

From: Braniff, Mimi P [mimi.braniff@delta.com]
Sent: 10/10/2017 9:59:53 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Baptist, Erik [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=10fc1b085ee14c6cb61db378356a1eb9-Baptist, Er]
CC: Steven Shimberg [sjshimberg@sjsolutions.biz]
Subject: RFS legal memo, PA delegation support letter for reform, RFS rally coverage
Attachments: 10062017 Energy Casey Letter to President Trump about RFS and RINs.pdf; memo on authority to create a RIN price collar 101017.docx

Mandy and Erik- I hope you both are well. As promised, attached is a memo outlining EPA's authority to create a RIN price collar. I have included Steve Shimberg on this email, who is the author of the memo. Please feel free to ask him any questions you may have.

Also, you may have heard Monroe Energy hosted a rally yesterday at our facility to support RFS reform. Congressmen Meehan, Brady, and Costello participated along with PBF Energy, PES, the USW, Building Trades and Local Steam Fitters. We had about 200 employees in the pouring rain. Below is a link to the CBS news coverage of the event. Fox was also there. I also included several news articles.

https://www.iqmediacorp.com/ClipPlayer/?ClipID=84d8e195-ca05-4dc5-946a-ded6c912f575

At the event we announced and provided to the press, a letter from Senators Toomey and Casey along with 12 PA Congressmen, to President Trump, seeking RFS reform. I have included the letter for your reference.

As always, if we can be helpful, please let me know. Mimi

From the Washington Examiner: http://www.washingtonexaminer.com/daily-on-energy-pruitt-perry-move-to-boost-coal/article/2176900

REFINERS, LAWMAKERS LASH OUT AT ETHANOL MANDATE: Independent refiners and a bipartisan group of lawmakers joined together Monday to call on President Trump to fix the Renewable Fuel Standard.

The RFS is the EPA's renewable fuel program that requires refiners to blend increasing amounts of ethanol and other biofuels into the nation's gasoline and diesel supply.

Icahn is back: But the independent refiners, including those represented by billionaire and former Trump adviser Carl Icahn, see the targets as burdensome and a hit to their bottom lines.

Employees of refiners Monroe Energy, Philadelphia Energy Solutions and PBF Energy joined with lawmakers at a press conference in Pennsylvania to call on Trump "to fix" the EPA's biofuel program.

Jobs on the line: "Collectively, these refineries support tens of thousands of jobs and contribute billions of dollars annually to the greater Philadelphia region's economy," said the organizing group Fueling American Jobs Coalition. "However, a federal government program is preventing these refineries from creating new jobs and it threatens refining jobs and those who depend on these facilities across the country."

What's the problem?: The group explained that the RFS requires local independent refineries to buy expensive credits from their rivals, the large multinational oil companies such as Exxon Mobil, to demonstrate that renewable fuels are being blended into the gasoline supply, despite not having the capability or resources to blend the fuels themselves.

Unfair competition: The bigger companies own both the production and distribution side of the fuel business, and can both generate the credits and blend the ethanol into fuel.

"This system subsidizes large, multinational oil companies at the expense of independent, local refineries. This is a flaw that President Trump can and must fix," the coalition said.

The refiners are pushing the EPA to make substantial changes to the RFS that would augment how credits can be generated to give the independent refiners a leg up.

Congress: Pennsylvania Reps. Pat Meehan and Ryan Costello, both Republicans, and Democrat Bob Brady gathered with the refinery workers Monday to call Trump to fix the RFS.

From the Philly paper:

Philly refiners urge Trump to protect their embattled industry

Updated: October 9, 2017 — 3:13 PM EDT

Andrew Maykuth / Staff
Refinery workers attend a rally at Monroe Energy in Trainer to urge President Trump to fix the Renewable Fuel Standard, which they say is hurting independent refiners.

by **Andrew Maykuth**, Staff Writer @Maykuth | amaykuth@phillynews.com

Several hundred refinery workers rallied Monday to urge President Trump to fix the Renewable Fuel Standard, saying the federal ethanol-blending rule is creating an unfair and onerous burden for the region's independent refiners.

In a driving rainstorm that became a metaphor for the storm that embattled refiners face in Washington, a bipartisan lineup of politicians, labor and business leaders called upon workers to pressure Trump to reconfigure the market for ethanol fuel credits, which they say has been hijacked by big oil interests and "Wall Street sharpies."

"The people gathered today represent the manufacturing jobs that President Trump and Congress talk so much about preserving," said Jeff Warmann, chief executive of Monroe Energy, which is owned by Delta Air Lines. "These are good jobs."

Monroe Energy in Trainer.

"This is manufacturing," said U.S. Rep. Patrick Meehan (R., Pa.). "You don't have to bring it back. It's here today. We just have to keep it."

The rally was organized by the Fueling American Jobs Coalition headed by the refiners, who have been fighting an uphill battle in Washington to rework the Renewable Fuel Standard. The RFS requires blending biofuel, principally ethanol, into motor fuels.

The coalition is trying to redefine its message so that it does not appear opposed to the RFS, which has strong legislative support in farming states, where most of the corn ethanol is produced. Rather, they want the administration to reconfigure who is responsible for shouldering the cost of biofuel credits called RINs, or Renewable Identification Numbers.

"This is not a fight against biofuels," said Warmann, who said Monroe Energy spends $500,000 a day for RINs, or more money per year than the $150 million Delta Air Lines spent in 2012 to buy the refinery.

The RFS program, established in the Energy Independence and Security Act of 2007, is administered by the Environmental Protection Agency to force the industry to blend ever-increasing volumes of biofuel like ethanol into motor fuel. Every gallon of ethanol that is blended into fuel generates a RIN, which is then sold to a producer or importer of gasoline.

Integrated refiners, who blend fuel and distribute it to their own retail outlets, generate their own ethanol credits. But merchant refiners, who sell fuel to blenders, need to buy RINs on the market to meet their obligations. The price of a RIN has escalated from a few pennies to more than a dollar.

Independent refiners — including Monroe Energy; Philadelphia Energy Solutions, which operates the South Philadelphia refinery complex; and PBF Energy, which owns refineries in Paulsboro and Delaware City, Del — say the soaring cost of the credits does not benefit producers of biofuel, but large oil companies and traders that control the unregulated RINs market.

"All it's doing is hurting the working men and women," said U.S. Rep. Bob Brady (D., Pa.), who spoke at the rally, along with U.S. Rep. Ryan Costello (R., Pa.). "It's just making the rich richer."

Supporters of the refiners suggest that the EPA could step in and rewrite the RFS rules to put caps on the price of RINs or other market controls.

From Reuters:

Philadelphia-area refiners urge Trump to reform biofuels program

By Jarrett Renshaw

TRAINER, Pa, Oct 9 (Reuters) - Oil refinery workers, executives and local politicians gathered near Philadelphia on Monday to urge the White House revamp the nation's renewable fuels program, arguing the future of their plants are at stake.

The U.S. renewable fuel program requires higher levels of ethanol and other biofuels to be blended into the nation's fuel pool, a requirement pitting the oil industry against the powerful farm lobby.

President Donald Trump has promised corn growers he would protect the program, while also signaling that he sympathizes with U.S. refiners who bear its costs.

The speakers told a crowd of about 100 that the tradable credits at the center of the renewable fuel program have been exploited by banks and trading firms, threatening the viability of merchant refiners like Monroe Energy and PBF Energy.

"Big oil companies and Wall Street investment firms are earning windfall profits and putting all this burden on the small, independent refiners," Jeff Warmann, chief executive of Monroe Energy, a subsidiary of Delta Air Lines Inc and operator of 185,000 barrel-per-day refinery outside of Philadelphia.

Warmann said speculators have driven up the price of the credits to the point his company spends $500,000 each day to comply with the program.

Ethanol supporters dispute the program is a problem, noting that the region's refineries were shuttering when credits traded at a pennies a piece.

"Big Oil needs to stop scapegoating the RFS and get about the business of providing consumers with lower cost," Renewable Fuels Association CEO Bob Dinneen said on Monday in a statement.

The U.S. Renewable Fuel Standard, or RFS, requires U.S. refiners and importers blend ethanol into their fuels or purchase credits from companies that do.

The credits cost pennies apiece in 2013 but have spent most of the past three years above 50 cents. The mostly widely traded credit was priced at 75 cents on Monday, traders said.

The higher cost will drive some of the region's five oil refineries out of business, speakers said, noting recent hurricanes underscored the importance of Philadelphia-area plants to the nation.

"Take the refineries on the East Coast off the grid, and we're all reliant on Texas to keep American energy secure," said U.S. Republican Representative Patrick Meehan, whose district includes the Delta refinery.

The credits fell to a year-to-date low of 34 cents in March amid optimism that Trump would revamp RFS and shift some costs to retailers and others, but it now appears he will not make that change.

The U.S. Environmental Protection Agency has angered the biofuels industry by calling for less biofuel blending. It also wants to allow exported ethanol to earn credits, increasing the pool of credits and driving down prices.

"This is manufacturing," Meehan said of the refineries threaten by higher costs. "You don't have to bring it back. It's here today. We just have to keep it."

(Reporting by Jarrett Renshaw; Editing by Marguerita Choy

Mimi Braniff | DELTA | Managing Director–Government Affairs
P: 202.243.3580 | 1212 New York Ave NW Ste 200 Washington, DC 20005

Congress of the United States

Washington, DC 20510

October 6, 2017

President Donald Trump
The White House
1600 Pennsylvania Avenue NW
Washington, DC 20500

Dear President Trump:

We write to ask your assistance in supporting thousands of well-paying energy sector jobs in Philadelphia and the surroundings area. Specifically, we are concerned that the high cost of compliance with the Renewable Fuel Standard (RFS) through the submission of Renewable Identification Number (RIN) credits is undermining the continued viability of the oil refining sector in the Northeast. We ask that your Administration address RINs in an effort to reduce compliance costs and support thousands of well-paying jobs in Pennsylvania's energy sector.

As you are aware, oil refineries are required to submit RINs to the Environmental Protection Agency (EPA) each year to demonstrate compliance with the RFS. However, merchant refiners have limited blending capacity and cannot generate enough RINs to meet their annual RFS obligations. Therefore, these refiners must purchase RINs on the secondary market, where prices have increased significantly and remain unpredictable. In recent years, RIN prices have skyrocketed, increasing compliance costs for northeast merchant refineries and putting thousands of energy jobs at risk.

In the Philadelphia region, Monroe Energy employs nearly 500 workers and Philadelphia Energy Solutions employs over 1,200, in addition to supporting thousands of indirect jobs in the energy, manufacturing, and transportation industries. According to both refineries, the cost of purchasing sufficient RINs to comply with the RFS exceeds their total payroll costs, which forces the facilities to forgo plans to expand production and hire additional workers. We are concerned that current compliance costs and the volatile RIN market may lead to the closure of one or more of these merchant refineries, which would have a devastating impact on the regional economy.

The Philadelphia-area refineries supply a significant amount of gasoline and diesel to motorists in the northeastern United States, and any loss of production due to the RFS could increase fuel prices and disrupt the region's gasoline supply. As demonstrated after Hurricane Harvey, the closure of several Gulf Coast refineries increased fuel costs across the country, and this scenario could have been more severe if either of the Philadelphia-area refineries were not operational. In an effort to prevent future price spikes and fuel disruptions, regulatory relief and RFS reform are needed so that the merchant refineries in Philadelphia can continue supplying affordable fuels and supporting well-paying jobs.

The issues surrounding the RFS are complex, but the need to save well-paying, family-sustaining jobs is not. We urge you to take all necessary steps to ensure that the Philadelphia-area refineries and the jobs they support are not jeopardized or eliminated by current federal energy policy. We stand ready to assist as your Administration strives to reduce compliance costs and support job creation, energy production, and national security.

Sincerely,

Robert P. Casey, Jr.
United States Senator

Pat Toomey
United States Senator

Mike Doyle
Member of Congress

Lou Barletta
Member of Congress

Dwight Evans
Member of Congress

Mike Kelly
Member of Congress

Robert A. Brady
Member of Congress

Patrick Meehan
Member of Congress

Brendan F. Boyle
Member of Congress

Glenn 'GT' Thompson
Member of Congress

Scott Perry
Member of Congress

Bill Shuster
Member of Congress

Keith Rothfus
Member of Congress

Ryan Costello
Member of Congress

SJSolutions, pllc

Memorandum

To: Chris Ruggiero, General Counsel, Monroe Energy, LLC
Mimi Braniff, Managing Director – Government Affairs, Delta Air Lines, Inc.

From: Steven Shimberg

Date: October 10, 2017

Subject: EPA's authority to create a RIN price collar under the RFS program

EPA has the authority to create a RIN price collar under the RFS program. The authority is found in the same statutory provisions that EPA relied on when it created RINs and developed an elaborate system of regulations to implement the RFS program.

RINs are not mentioned in the statute. They were created by EPA in the 2007 RFS1 regulations[1] and retained in the 2010 RFS2 regulations[2].

This memorandum reviews:

1. The relevant statutory provisions;
2. EPA statements in the 2007 RFS1 rule about RINs and the scope of its authority to develop the credit program;
3. EPA statements in the 2010 RFS2 rule about RINs and the RIN trading system; and
4. Examples of EPA RFS regulatory decisions that demonstrate the breadth of EPA's authority.

This memorandum concludes with an outline of one approach to create and implement a RIN price collar by regulation.

[1] RFS1 Final Rule, 72 Fed. Reg. 23900 (May 1, 2007); available at https://www.gpo.gov/fdsys/pkg/FR-2007-05-01/pdf/E7-7140.pdf
[2] RFS2 Final Rule, 75 Fed. Reg. 14670 (March 26, 2010); available at https://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf

1. Statutory Provisions

EPA is required to implement a renewable fuel program under section 211 of the Clean Air Act as amended by the Energy Policy Act of 2005 and the Energy Security Independence and Security Act of 2007 (EISA).[3]

There are two statutory provisions that provide the authority for EPA to create a RIN price collar:

First, paragraph (2)(A)(i) of Section 211(o) provides the general, overarching directive and authority for the Administrator to develop regulations to implement the RFS program. The relevant statutory language directs the Administrator to:

> "promulgate regulations to ensure that gasoline sold or introduced into commerce in the United States (except in noncontiguous States or territories), on an annual average basis, contains the applicable volume of renewable fuel" and to "revise the regulations under this paragraph to ensure that transportation fuel sold or introduced into commerce in the United States (except in noncontiguous States or territories), on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel…."

Second, paragraph (5) of Section 211(o) directs EPA to include in the implementing regulations a credit program. There is minimal statutory guidance on how the credit program is to operate and there is no mention of RINs. The relevant statutory language follows:

> (5) Credit program
>
> (A) In general
>
> The regulations promulgated under paragraph (2)(A) shall provide—
>
> (i) for the generation of an appropriate amount of credits by any person that refines, blends, or imports gasoline that contains a quantity of renewable fuel that is greater than the quantity required under paragraph (2);
>
> (ii) for the generation of an appropriate amount of credits for biodiesel; and

[3] Section 211(o) of the Clean Air Act is codified at 42 U.S.C. §7545(o); available at https://www.gpo.gov/fdsys/pkg/USCODE-2010-title42/pdf/USCODE-2010-title42-chap85-subchapII-partA-sec7545.pdf page 13.

(iii) for the generation of credits by small refineries in accordance with paragraph (9)(C).

(B) Use of credits

A person that generates credits under subparagraph (A) may use the credits, or transfer all or a portion of the credits to another person, for the purpose of complying with paragraph (2).

(C) Duration of credits

A credit generated under this paragraph shall be valid to show compliance for the 12 months as of the date of generation.

2. EPA statements in the 2007 RFS1 rule about RINs and the scope of its authority to develop the credit program

As noted above, RINs are not mentioned in the statute. They were created by EPA in the 2007 RFS1 regulations.[4] As part of that rulemaking, the Agency noted that the law required promulgation of "a credit trading program" and gave EPA broad authority to determine the structure of the program as well as the rules governing operation of the credit program.

> The Agency must determine who can generate credits, under what conditions credits may be traded, how credits may be transferred from one party to another, and the appropriate value of credits for different types of renewable fuel....[5]
>
> Various aspects of the program require additional development by the Agency beyond the specifications in the Act.[6]

EPA explained why the trading provisions "comprise an integral element of compliance" under the RFS program:

> Many obligated parties do not have access to renewable fuels or the ability to blend them, and so must use credits to comply. The RFS trading program is also unique in that the parties liable for meeting the standard (refiners, importers, and blenders of gasoline) are not generally the parties who make the

[4] RFS1 Final Rule, 72 Fed. Reg. 23900 (May 1, 2007); available at https://www.gpo.gov/fdsys/pkg/FR-2007-05-01/pdf/E7-7140.pdf

[5] Id. at 23904, col 1

[6] Id. col 2

> renewable fuels or blend them into gasoline. This creates the need for trading mechanisms that ensure that the means to demonstrate compliance will be readily available for use by obligated parties.[7]

In developing the trading program, EPA sought to "satisfy a number of guiding principles, including, for example, that the compliance and trading program should provide certainty to the marketplace and minimize cost to the consumers; that the program should preserve existing business practices for the production, distribution, and use of both conventional and renewable fuels; that the program should be designed to accommodate all qualifying renewable fuels; that all renewable volumes produced are made available to obligated parties for compliance; and that the Agency should have the ability to easily verify compliance to ensure that the volume obligations are in fact met."[8]

The Agency used its authority under paragraphs 2 and 5 of Section 211(o) to create RINs and to have each RIN serve two functions:

> It is direct evidence of compliance and, after a compliance year is over, excess RINs serve the function of credits for overcompliance.[9]

EPA asserted that "[o]ur RIN-based program fulfills all the functions of a credit trading program" and "provides additional flexibility in that it permits all RINs to be transferred between parties before they are deemed to be in excess of a party's annual RVO at the end of the year."[10]

EPA summarized its RIN-based compliance and trading program by noting that:

> EPA's final program was developed in light of the somewhat unique aspects of the RFS program. As discussed earlier, under this program the refiners and importers of gasoline are the parties obligated to comply with the renewable fuel requirements. At the same time, refiners and importers do not generally produce or blend renewable fuels at their facilities and so are dependent on the actions of others for the means of compliance. Unlike EPA's other fuel programs, the actions needed for compliance largely center on the production,

---

[7] Id.
[8] Id.
[9] Id. at 23930, col 1
[10] Id.

> distribution, and use of a product by parties other than refiners and importers. In this context, we believe that the RIN transfer mechanism should focus primarily on facilitating compliance by refiners and importers and doing so in a way that imposes minimum burden on other parties and minimum disruption of current mechanisms for distribution of renewable fuels....[11]
>
> We continue to believe that there is a need to provide for more open trading in the RFS program and that this need warrants a unique approach for this rule. First, unlike other programs where credits generally represent overcompliance with an applicable standard and are thus supplemental to the means of compliance, under the RFS program RINs are the fundamental unit for compliance. There will be many more RINs in the RFS program than credits in other programs, and the trading structure must maximize the fluidity of those RINs. A wider RIN market will make it easier for obligated parties to get access to RINs.[12]

The volatility in the RIN market since 2013 is evidence that many of the assumptions EPA made about the RIN-based compliance and trading program in 2007 are no longer valid. To "make it easier for obligated parties to get access to RINs" EPA should use its authority to modify the RIN-based program by, among other things, creating a RIN price collar.

3. EPA statements in the 2010 RFS2 rule about RINs and the RIN trading system

In the 2009-2010 RFS2 rulemaking, EPA acknowledged that there was an ongoing, unanticipated change in market conditions; decided to defer taking action to address the problems; and pledged to monitor the situation and revisit the issues as appropriate. Action by EPA to address these problems is long overdue.

As noted in the NPRM:

> The approach we took for RFS1 was based on our expectation at that time that there would be an excess of RINs at low cost, and our belief that the ability of RINs to be traded freely between any parties once separated from renewable

[11] Id. at 23937, col 3
[12] Id. at 23944, col 2

> fuel would provide ample opportunity for parties who were in need of RINs to acquire them from parties who had excess....
>
> Following the new requirements under EISA, the required volumes of renewable fuel will be increasing significantly above the levels required under RFS1. These higher volumes are already resulting in changes in the demand for RINs and operation of the RIN market. First, obligated parties who have excess RINs are increasingly opting to retain rather than sell them to ensure they have a sufficient number for the next year's compliance.... Third, major integrated refiners who operate gasoline marketing operations have direct access to RINs for ethanol blended into their gasoline, while refiners whose operations are focused primarily on producing refined products do not have such direct access to RINs. The result is that in some cases there are significant disparities between obligated parties in terms of opportunities to acquire RINs. If those that have excess RINs are reluctant to sell them, those who are seeking RINs may be forced to market a disproportionate share of E85 in order to gain access to the RINs they need for compliance. If obligated parties seeking RINs cannot acquire a sufficient number, they can only carry a deficit into the following year, after which they would be in noncompliance if they could not acquire sufficient RINs. The result might be a much higher price for RINs (and fuel) in the marketplace than would be expected under a more liquid market.
>
> Given the change in circumstances brought about through EISA, it may be appropriate to consider a change in the way that obligated parties are defined to more evenly align a party's access to RINs with that party's obligations under the RFS2 program.[13]

EPA committed in the final rule that:

> We will continue to evaluate the functionality of the RIN market. Should we determine that the RIN market is not operating as intended, driving up prices

[13] RFS2 NPRM, 74 Fed. Reg. 24904, at 24963 col. 2 and 3 (May 26, 2009); available at https://www.gpo.gov/fdsys/pkg/FR-2009-05-26/pdf/E9-10978.pdf. In this excerpt, EPA addresses the rationale for modifying the definition of obligated party "to more evenly align a party's access to RINs with that party's obligations under the RFS2 program." The discussion is equally relevant and applicable to creating a RIN price collar.

for obligated parties and fuel prices for consumers, we will consider revisiting this provision in future regulatory efforts. [14]

4. Examples of EPA RFS regulatory decisions which demonstrate the breadth of EPA's authority

EPA has interpreted the statute as giving the Agency wide discretion to devise various aspects of the RFS program, including the RIN-based compliance and trading program. Examples of other RFS regulatory decisions which demonstrate the breadth of EPA's authority include creation of the following:

- a "small refiner" exemption (40 C.F.R. §80.1142) that went beyond the statutorily prescribed "small refinery" exemption (40 C.F.R. §80.1141)[15];
- a formula to calculate Renewable Volume Obligations (40 C.F.R. §80.1407);
- equivalence values for different renewable fuels (40 C.F.R. §80.1415);
- a petition process for evaluation of new renewable fuels pathways (40 C.F.R. §80.1416);
- a focus on production of renewable fuel as a surrogate for use of such fuel (40 C.F.R. §80.1416);
- a 20% cap on the use of RINs generated the previous year when demonstrating compliance with an RVO for the current year (40 C.F.R. §80.1416);
- requirements for exporters of renewable fuels (40 C.F.R. §80.1430);
- an EPA Moderated Transaction System (EMTS) (40 C.F.R. §80.1452);
- a list of prohibited acts (40 C.F.R. §80.1460);
- a list of who is liable for violations under the RFS program (40 C.F.R. §80.1461);

[14] RFS2 Final Rule, 75 Fed. Reg. 14670, at 14722 col. 2 (March 26, 2010); available at https://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf

[15] EPA interpreted the statutorily prescribed exemption as a directive that did not limit the Agency's discretion and authority to create and implement an additional exemption. See discussion in RFS1 Final Rule, 72 Fed. Reg. at 23924, col 2; available at https://www.gpo.gov/fdsys/pkg/FR-2007-05-01/pdf/E7-7140.pdf. Similarly, the statutory directive to make cellulosic biofuel credits available for sale whenever the Administrator reduces the minimum cellulosic biofuel volume (42 U.S.C. §7545(o)(7)(D)(ii)) does not diminish EPA's authority and discretion to create and implement a RIN price collar for other categories of biofuels.

- additional requirements for a foreign RIN owner and RIN- generating foreign producers and importers of renewable fuels for which RINs have been generated by the foreign producer (40 C.F.R. §80.1466 and §80.1467); and
- requirements for Quality Assurance Plans (40 C.F.R. §80.1469).

Conclusion and outline of one approach to create and implement a RIN price collar by regulation

EPA created the RIN compliance and trading program in 2007 based on "our expectation at that time that there would be an excess of RINs at low cost."[16] That expectation was met through 2012. Since that time, however, RIN prices have increased dramatically and the RIN market has not been operating as originally intended.

A RIN price collar is necessary to improve operation of the RIN credit program, ensure market stability, and more evenly align a party's access to RINs at low cost with that party's obligation under the RFS program.

One approach to creating and implementing a RIN price collar by regulation could include the following key elements:

1. Create a RFS Cost Containment Reserve.
2. Fill the Reserve --
    a. Allow RIN-long obligated parties to sell a portion (e.g. 50%) of their excess RINS (RINs that exceed the sum of their RVO and the allowable 20% carry forward) but require them to transfer a portion (e.g. 50%) of their excess RINs to EPA for deposit into the Cost Containment Reserve;
    b. Allow non-obligated parties to sell a portion (e.g. 25%) of the RINs they hold but require them to transfer a portion (e.g. 75%) of their RINs to EPA for deposit in the Cost Containment Reserve.
3. Sale of Reserve Credits --
    a. Make Cost Containment Reserve Credits available for purchase by any RIN-short obligated party;

[16] RFS2 NPRM, 74 Fed. Reg. at 24963, col 2

b. Make Cost Containment Reserve Credits available at or below the 2012 average market price of RINs for each category (2.8 cents per D6 conventional RIN; 61.7 cents per D5 advanced RIN; and $1.097 per D4 bio-diesel RIN).

4. Supply of Credits --
   a. If the number of credits in the Reserve is insufficient to meet the demand, increase the supply by increasing the percentage of credits required to be transferred to the Agency under 2(a) and/or 2(b) above;
   b. If the number of credits in the Reserve exceeds the demand, keep them in the Reserve and carry them forward for sale and use the following year.
5. Use of Reserve Credits – RFS Cost Containment Credits should only be used for compliance with an RVO and only for the year in which the credit was sold by EPA.
6. Limitations –
   a. Prohibition on banking – Any person who buys a RFS Cost Containment Credit may not carry forward any RIN credits to the following compliance period;
   b. Prohibition on sale – No person may purchase a RFS Cost Containment Credit within [180 days] of selling or transferring a RIN to another person.

If you have any questions about the contents of this memorandum, I can be reached at:

STEVEN J. SHIMBERG
SJSOLUTIONS PLLC
Environmental Law/Policy, Counseling/Advocacy
sjshimberg@sjsolutions.biz
202.689.4920

mcmahontrucks.com
McMahon TRUCK CENTERS
3609 Trailer Drive • Charlotte, NC 28269 • 704.597.1240

October 17, 2017

The Honorable Scott Pruitt

Administrator

Environmental Protection Agency

Office of the Administrator 1101A

1200 Pennsylvania Avenue, NW

Washington, DC 20460

My brother, Brad, and I are private business owners with Heavy Duty, Class 8 Dealerships in Nashville, TN, Charlotte, NC, Rock Hill, SC, Columbus, OH and Marietta, OH. I ask you to keep the volume cap on "glider vehicles" as written in the final Greenhouse Gas Phase 2 regulation.

Simply, glider vehicles are sold against us but with an unfair competitive advantage.

Environmental Disadvantage: Today's new trucks meet US '10 emission levels by the installation of expensive "chemical factories" behind the engine (the SCR and DPF) that glider kits avoid to compete. As environmentally minded business owners, selling state of the art products that comply with EPA's strict emissions standards, ***Keeping the Cap*** is NOT a cutting back of the old beaurocratic "red tape" of over-regulation. Also, removing the cap does NOT help everyday Americans get ahead to a brighter future by allowing the re-running of yesterday's technology. Rather, ***Keeping the Cap*** is reasonable stewardship of ***Keeping*** with the spirit and intent of the rules as they are written.

Income and Tax Disadvantage: We are required to pay a 12% Federal excise tax on the sale price of every truck we sell. Glider Vehicles may not have to pay the excise tax. This tax is used to fund the Federal highway trust fund which helps pay for our roads and bridges. Ultimately, we are at a 12% unfair price disadvantage on the vehicles we sell to build highway infrastructure.

We have lost sales in every state in which we operate to glider vehicles, and it has NEGATIVELY impacted our business. It is quickly estimated that we have lost approximately $10MUS per year in truck sales including the related $1.2MUS in FET that is not going into the highway trust fund.

Very plainly, ***Keeping the Cap*** helps level the playing field so that we can compete fairly.

Thank you very much for the great attention you are paying to this important matter. If you have any additional questions, feel free to contact me at mmcmahon@mcmahontrucks.com.

Very truly yours,

Mike McMahon
President & CEO

Message

From: Geoffrey Moody [GMoody@afpm.org]
Sent: 10/24/2017 2:23:43 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Available?

Mandy, sorry again about Friday, but just wanted to follow up on this. Do you have some time to catch up this week?

From: Geoffrey Moody
Sent: Friday, October 20, 2017 7:37 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Available?

Hey Mandy, sorry about that. I got caught in a meeting. Can we catch up next week?

Sent from my iPhone

On Oct 20, 2017, at 4:47 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

Hey Geoff, I just tried your office number - is there a better number to reach you?

-----Original Message-----
From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Friday, October 20, 2017 9:21 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Available?

That works for me

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Friday, October 20, 2017 4:48 AM
To: Geoffrey Moody <GMoody@afpm.org>
Subject: Re: Available?

Hey Geoff, I don't have any time in the morning, but do at 4:45. Let me know if that works.
Best,
Mandy

Sent from my iPhone

On Oct 19, 2017, at 11:27 PM, Geoffrey Moody <GMoody@afpm.org> wrote:

Mandy, are you available for a call tomorrow morning?

Sent from my iPhone

Message

From: Memmott, Justin (EPW) [Justin_Memmott@epw.senate.gov]
Sent: 10/23/2017 2:31:15 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Barrasso letters on EPA's Part 192 rulemaking
Attachments: 10-20-16 JB et al to OMB (Donovan).pdf; 12-1-16 JB et al to OIRA (Shelanski).pdf

Mandy and Alex,

Here are Barrasso's two letters on EPA's Part 192 rulemaking.

The first one was sent by Barrasso, Cornyn, and Fischer to OMB.
The second letter was sent by Inhofe, Capito, and Barrasso to OIRA, specifically.

Thanks for your attention to this issue.

Justin J. Memmott
Majority Senior Counsel
Senate Environment and Public Works Committee
Personal Phone / Ex. 6

United States Senate

WASHINGTON, DC 20510

October 20, 2016

The Honorable Shaun Donovan
Director
Office of Management and Budget
725 17th Street NW
Washington, D.C. 20503

Dear Mr. Donovan:

We are concerned about the Environmental Protection Agency's (EPA) rulemaking requiring in situ uranium recovery (ISR) operators to conduct long-term groundwater monitoring under 40 C.F.R. Part 192. To date, EPA has not sufficiently articulated the threat to the environment or public health that it is attempting to address in this rulemaking. As a result, it is not clear that the benefits of the proposed rule or a substantially similar final rule would outweigh the costs. We, therefore, ask you to direct EPA to withdraw its proposed rule and collect additional data on the costs and benefits of its proposal prior to taking any further action on this rulemaking.

On January 26, 2015, EPA proposed a rule requiring ISR operators to conduct groundwater monitoring for up to 30 years following the end of ISR operations. EPA states that "current industry practices for restoration and monitoring of the affected aquifer may not be adequate to prevent either the further degradation of water quality or the more widespread contamination of groundwater that is suitable for human consumption." EPA says "[m]ost ISR sites historically have been unable to meet restoration goals for all constituents even after extensive effort." It cites as evidence a study titled, "Groundwater Restoration at Uranium In-Situ Recovery Mines, South Texas Coastal Plain," published in 2009, by Susan Hall of the U.S. Geological Survey.

EPA argues that "[b]ecause monitoring after restoration is typically conducted for only a short period, we find it difficult to characterize the probability or magnitude of future contamination problems, or the costs involved in remediating such future contamination." It says, "[s]imilarly, because ISR…and any subsequent contamination may take years, decades or even longer to reach groundwater being consumed by humans, it is difficult to characterize the benefits of our proposal by applying typical Agency metrics." Instead, EPA conducted a largely "qualitative assessment" of the benefits. Setting aside the unknowns (or perhaps *on account of* them), EPA says "[i]t is likely, however, that the costs of such future remediation would far exceed the costs of the more extensive monitoring (in all phases of site activity) that we are proposing today."

We do not share EPA's confidence that the benefits of the proposed rule would exceed the costs. While EPA repeatedly cites Hall's study in its proposed rule, it fails to note that the study finds nearly all the examined well fields "are characterized by groundwater elevated in multiple MCLs [maximum contaminant levels] prior to mining." In other words, "[t]hese well fields would require pretreatment to be used as a source for drinking water." EPA also fails to note that "[o]f those elements for which MCL is established, the majority of [well fields] showed…decreases in arsenic, cadmium, fluoride, lead, mercury, nitrate, and radium to below baseline for the majority of well fields." That is, ISR activities had positive as well as negative effects on the well fields.

Finally, EPA does not explain that Hall's study did not address whether a failure to meet all restoration goals at ISR sites poses any risk to the environment or public health.

ISR has a 40-year history in the United States. EPA, by its own admission, has yet to confirm a single case where ISR activities have affected a source of drinking water. However, instead of writing a rule based on data from existing ISR well fields, EPA has proposed a rule based largely on its "qualitative view of the situation." EPA can and must do better. We, therefore, ask that you direct EPA to withdraw its proposed rule and work with ISR operators and the Nuclear Regulatory Commission, the principal regulator of ISR activities, to collect additional data on the costs and benefits of its proposal. At a minimum, your agency should use its authority to conduct an independent cost-benefit analysis of EPA's final rule before taking further action on that rule.

Thank you for your consideration and we look forward to your prompt response.

Sincerely,

John Barrasso, M.D.
United States Senator

John Cornyn
United States Senator

Deb Fischer
United States Senator

JAMES M. INHOFE, OKLAHOMA, CHAIRMAN

DAVID VITTER, LOUISIANA
JOHN BARRASSO, WYOMING
SHELLEY MOORE CAPITO, WEST VIRGINIA
MIKE CRAPO, IDAHO
JOHN BOOZMAN, ARKANSAS
JEFF SESSIONS, ALABAMA
ROGER WICKER, MISSISSIPPI
DEB FISCHER, NEBRASKA
MIKE ROUNDS, SOUTH DAKOTA
DAN SULLIVAN, ALASKA

BARBARA BOXER, CALIFORNIA
THOMAS R. CARPER, DELAWARE
BENJAMIN L. CARDIN, MARYLAND
BERNARD SANDERS, VERMONT
SHELDON WHITEHOUSE, RHODE ISLAND
JEFF MERKLEY, OREGON
KIRSTEN GILLIBRAND, NEW YORK
CORY A. BOOKER, NEW JERSEY
EDWARD J. MARKEY, MASSACHUSETTS

RYAN JACKSON, MAJORITY STAFF DIRECTOR
BETTINA POIRIER, DEMOCRATIC STAFF DIRECTOR

United States Senate

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WASHINGTON, DC 20510-6175

December 1, 2016

The Honorable Howard Shelanski
Administrator, Office of Information and Regulatory Affairs
Office of Management and Budget
725 17th Street NW
Washington, D.C. 20503

Dear Administrator Shelanski:

We are writing to you regarding the Environmental Protection Agency's rulemaking related to in situ uranium recovery (ISR) and groundwater monitoring under 40 CFR Part 192.

This rulemaking has insufficiently analyzed the alleged benefits, yet the significant costs it imposes would likely mark the end of in situ uranium recovery (ISR) in the United States. In 2015, the domestic uranium industry produced 3.7 million pounds of uranium,[1] and ISR accounted for 92 percent of that production.[2] We are already dependent on imported uranium for more than 94 percent of the fuel needed for our domestic nuclear reactors.[3] If this rule is finalized, we will lose our domestic uranium industry, and become entirely dependent on imported uranium to provide 20 percent of the electricity produced in the United States.

EPA staff has acknowledged in public forums that they are not aware of a single example of an ISR uranium project that has caused harm to a non-exempt, adjacent aquifer. Similarly, the Nuclear Regulatory Commission, the primary ISR regulator, has not identified any such harm. In response to questions for the record following a hearing before Committee on October 7, 2015, the NRC affirmatively stated it "has not documented any case where recovery solutions from an NRC-licensed uranium in-situ facility have migrated beyond the licensed (permit) area and contaminated drinking water."

Given the significant impact of this rule, the failure of the EPA to do an adequate cost-benefit analysis, and the failure of the EPA to provide any justification for the new stringent requirements the agency seeks to impose, it is critical the OMB carefully review this proposal and meet with all interested stakeholders, including the domestic uranium producers who would be most affected.

[1] Energy Information Agency (EIA), Domestic Uranium Production Report, May 5, 2016.
[2] Estimate based on total EIA production data and public filings from domestic uranium companies.
[3] EIA, Domestic Uranium Production Report, May 5, 2016.

PRINTED ON RECYCLED PAPER

We are certain that once OMB has reviewed all the facts, you will agree that this rulemaking should be rejected outright.

Sincerely,

Shelley Moore Capito, Chairman
Subcommittee on Clean Air and Nuclear Safety
U.S Senate

James M. Inhofe, Chairman
Committee on Environment and Public Works
U.S Senate

John Barrasso, M.D.
United States Senate

Message

From: Meyers, Robert [RMeyers@crowell.com]
Sent: 10/20/2017 7:02:22 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: PFI

Just left voicemail before I read this -- yes that time will work

Robert J. Meyers
(202) 624-2967
(202) 306-5254 (c)
RMeyers@crowell.com
Crowell & Moring LLP
Privileged and Confidential
Attorney-Client Communication
Attorney Work Product

This message contains privileged and confidential information. IF IT WAS SENT TO YOU BY MISTAKE, DO NOT READ IT. Instead, please notify the sender (or postmaster@crowell.com) by reply e-mail, and delete this e-mail. Unauthorized dissemination, forwarding or copying of this e-mail is strictly prohibited.

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Friday, October 20, 2017 2:55 PM
To: Meyers, Robert
Subject: PFI

Hey Bob,
Great seeing you the other night. I apologize but a last minute meeting with OMB popped up at 3 pm. Can we move the discussion to Monday morning at 10 am?
Best,
Mandy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Lindsay McCoy [lmccoy@trucksalesgroup.com]
Sent: 10/18/2017 7:13:25 PM
To: Baptist, Erik [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=10fc1b085ee14c6cb61db378356a1eb9-Baptist, Er]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: susan.alt@volvo.com
Subject: Letter from VoMac- Gliders
Attachments: Glider Issue.pdf

Good Afternoon,

Please see the attached letter from VoMac Truck Sales and Service, Inc. President Philip Morelli pertaining to the ongoing glider issue.

Thank You,

Lindsay Girod

Lindsay Girod
MARKETING

MACK
VOLVO
Vollac Truck Sales

PH: (260) 749-5061
(800) 824-9354

12242 Declaration Dr.
New Haven, IN 46774

lmccoy@trucksalesgroup.com
www.trucksalesgroup.com

VOMAC TRUCK *Sales & Service, Inc.*

www.vomacsales.com | 12242 Declaration Dr., New Haven, IN 46774 | Phone: (260) 749-5061 | Toll Free: (800) 824-9354

October 17, 2017

To Whom It Concerns,

As a private business owner with operations in New Haven, IN; Evansville, IN; Vincennes, IN; and Terre Haute, IN, I ask you to keep the volume cap on "glider vehicles" as written in the final Greenhouse Gas Phase 2 regulation.

Simply put, glider vehicles are sold against us and with an unfair competitive advantage.

Today's new trucks meet US '10 emission levels by the installation of an expensive "chemical factory" behind the engine: the SCR and DPF. Because glider vehicles don't meet the current emission standards, they avoid these expensive "chemical factories" that we, as conscientious business owners complying with the EPA's strict emissions standards, provide our customers allowing the least amount of emissions possible.

Also, we are required to pay a 12-percent Federal Excise Tax on the sale price for every truck we sell. This tax is used to fund the Federal Highway Trust Fund which helps pay for our roads and bridges. Glider vehicles may not have to pay the excise tax. So, not only are we, as private business owners, at an unfair price disadvantage, but also the fund to build highway infrastructure is lessened with every glider vehicle sold in place of a truck meeting the EPA's emission restrictions.

I have lost sales to glider vehicles and it negatively impacts my business. A few of the deals we have lost include those with the following potential customers:

Materials Transport
Wayne Wilkens Trucking
Herrington Transport
On Line Transport
RBW
GN Trucking- IN
Ray Jones Trucking- KY
Clay's Trucking-KY
LR Chapman- KY
Rite Crete- KY
D&G- KY
Western Kentucky transport- KY
Moorman Transport- KY
Hutchison Trucking- KY
Jeff Lear Trucking- KY
Gibco Motor Express- IN
Bestway Express- IN
Wayne Wilkens Trucking- IN

RG Berry Trucking- IL
Eagle Valley Inc- IL
Sunshine Distributors- IL
Old Pony Farms- IL
Vision IV- IN
Heritage Petroleum- IN
Duff Trucking- IN
Jeremy Carter Trucking- IL
Poshards Trucking- In
Murphy Trucking- IL
Hoehn Transportation- IN
Wes Neuman Trucking- IL
David Wilkens- IN
JS Transport- IN
TIMCO- IL
Dillon Trucking- IN
Robinson Brothers Trucking- IN

I simply want a level playing field so that we can fairly compete. Please feel free to contact me at pmorelli@trucksalesgroup.com for any further discussion.

Sincerely,

Philip Morelli
VoMac Truck Sales & Service, Inc. President

Message

From: Lafferty, Susan [susanlafferty@eversheds-sutherland.com]
Sent: 10/20/2017 2:02:15 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: McCullough, David [davidmccullough@eversheds-sutherland.com]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Montauk Request for Meeting: Cellulosic Fuel

Hi Alex – Monday November 6 at 2 pm ET works well for us. Montauk would is available to attend in person in DC if that works on your end. Otherwise, we are pleased to have a call.

Should we expect this to go to 2:30 or 3?

Thank you for your help - -Susan

Susan Lafferty | Partner | T: +1.202.383.0168

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Thursday, October 19, 2017 4:49 PM
To: Lafferty, Susan <SusanLafferty@eversheds-sutherland.us>
Cc: McCullough, David <DavidMcCullough@eversheds-sutherland.us>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Montauk Request for Meeting: Cellulosic Fuel

Susan,

We could do a call Monday, November 6th at 11:30AM or 2:00PM or the 7th at 2:00PM - other than that we are looking at the beginning of December right now.

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Lafferty, Susan [mailto:susanlafferty@eversheds-sutherland.com]
Sent: Thursday, October 19, 2017 2:11 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: McCullough, David <davidmccullough@eversheds-sutherland.com>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Montauk Request for Meeting: Cellulosic Fuel

Mandy – thank you . Alex – if there are a few dates that might work, we can take those to Montauk. Thank you – Susan

Susan Lafferty | Partner | T: +1.202.383.0168

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Wednesday, October 18, 2017 2:29 PM
To: Lafferty, Susan <SusanLafferty@eversheds-sutherland.us>

Cc: McCullough, David <DavidMcCullough@eversheds-sutherland.us>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Montauk Request for Meeting: Cellulosic Fuel

Thanks, Susan. I'm looping in Alex to help organize the logistics.
Best,
Mandy

From: Lafferty, Susan [mailto:susanlafferty@eversheds-sutherland.com]
Sent: Wednesday, October 18, 2017 2:19 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: McCullough, David <davidmccullough@eversheds-sutherland.com>
Subject: Montauk Request for Meeting: Cellulosic Fuel

Hello Mandy -- We are writing on behalf of Montauk Energy Holdings, LLC, which is responsible for more than one-fifth of all cellulosic RINs generated in 2016 and 2017. Montauk would like to meet with you to introduce you to the company and the cellulosic biogas industry. Given the current discussions regarding annual standards and a possible reset of the volumes, such a discussion would be timely and we believe useful to the agency as it moves forward on RFS issues. We have also requested a meeting with relevant staff (Paul Machiele and Dallas Burkholder), but we very much believe that we can add value to Administrator Pruitt's efforts on RFS through a meeting with you.

Please see the attached comments the Company submitted to EPA for more information about Montauk and cellulosic fuel.

Are there dates that would be best for you and your team? We will be as flexible as possible as Montauk is very eager to meet with EPA.

Best regards – Susan

Susan Lafferty | Partner | Eversheds Sutherland (US) LLP

T: +1.202.383.0168
Biography | vCard

www.eversheds-sutherland.com

Eversheds Sutherland
Client Commitment. Innovative Solutions. Global Service.

Eversheds Sutherland (US) LLP is part of a global legal practice, operating through various separate and distinct legal entities, under Eversheds Sutherland. For a full description of the structure and a list of offices, please visit www.eversheds-sutherland.com.

This e-mail message, together with any attachments, is intended only for the above named recipient(s) and may contain privileged and/or confidential information. If you are not an intended recipient, you must not review, copy or show the message and any attachments to anyone. Please reply to this e-mail and highlight the mistaken transmission to the sender, and then immediately delete the message.

Message

From: Agile Development in Government Training Workshop [Training@PotomacForum-AgileInGov.org]
Sent: 10/27/2017 2:32:01 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: DHS, CMS, Digital Services Speakers at Agile in Government Workshop

Outstanding Government Speakers - DHS, CMS, Digital Services + Agile Development & Contracting
- Please Forward to Others in Your Organization Interested in Agile Development for Software Development, Contracting or Other Applications -
----

Agile Development in Government Training Workshop IX:

Laying the Right Foundation for Agility Within Your Agency
What Executives, Managers and Staff Need to Know

A "How to" Workshop Discussing Best Practices and Lessons Learned

Wednesday, November 8, 2017

Willard InterContinental Hotel
Washington, D.C.

Link to Potomac Forum Website: www.PotomacForum.org

Government & Industry Invited to Attend

Sponsored by:
Potomac Forum, Ltd
providing training to government since 1982

Previous Eight Agile Workshops
Rated As Excellent By
Government & Industry Students

Potomac Forum Workshops are 100% Training and
Not Sales or Marketing Events

Government Speakers:

Keynote
William (Bill) Pratt
Director, IT Standards & Program Support
Office of the CIO
Department of Homeland Security
(awaiting agency approval)
(Author of the Widely Acclaimed
DHS AGILE Guidebook Used by DHS and
Many Other Government Agencies)

Featured Speaker
Jonathan Mostowski
Member of the Defense Digital Service Team,
The White House and Pentagon

Tia Norman
Chief, Agile Maturity & Governance
Office of the CIO
Department of Homeland Security
(awaiting agency approval)

Melissa Cohen
Director, Policy and Programs Group
Center for Medicare Medicaid Services (CMS)

Daniel Levenson
Digital Service Contracting Advisor
Center for Medicare & Medicaid Services (CMS)

Additional Government Speakers
to be Announced

With the current Administration's emphasis on IT Modernization coupled with today's demanding environment and reduced budgets, most Federal agencies are at some level

of Agile adoption or transformation to increase efficiencies and meet these challenging demands. However, many would welcome insight into how best to address the cultural issues and other factors contributing to impediments to Agile adoption. Knowing how to achieve success in this process by laying the right foundation will be the key focus of this workshop.

What You Will Learn:

- **What typically drives the pockets of resistance in government agencies and how can they be dealt with successfully?**
- **How will my role and responsibilities change, and how can I best prepare myself?**
- **How can we ensure that our contracting for Agile Digital Services is not in conflict with the FAR?**
- **What are some innovative contracting initiatives that are already working for government?**
- **We've already started down the path of Agile adoption. What are some of the commercial best practices that we could adopt in our government agency?**
- **What should we know about selecting and interacting with Agile partners from industry?**
- **What kind of training should my government staff be looking for to best manage the government/vendor relationship on my Agile projects?**

Why You Should Attend:
- As more and more government agencies move to adopt Lean and Agile practices, there must be assurance that they are keeping within the regulatory boundaries unique to the Federal government. Many agencies are already doing this very successfully. This workshop will show you how they are navigating these challenges.

- There are agencies that are eliminating costly mistakes and downtime by successfully adopting Lean and Agile practices. Come and hear their experiences and lessons learned.

- Agile practices not only take technical expertise, but require deep cultural change. Hear from experts and daily practitioners about the importance of managing these cultural

challenges and how they are successfully driving cultural change based on their real world experiences.

Who Should Attend:

- **CIOs, CTOs, Federal IT Executives, Managers and Staff**
- **Contracting officers Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their Agencies**
- **Acquisition professionals**
- **Agencies new to adopting Agile projects**
- **Agencies that have already started to adopt Agile practices who want to move to the next level of agility**
- **Development and Operations teams facing ongoing challenges to deployment**
- **Program and project managers**
- **Agile teams facing ongoing challenges to acquisition**
- **Chief Financial Officers and Staff**
- **Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their agencies**
- **Project and program managers who want to better understand their role in an Agile environment**
- **Inspector Generals and Staff**
- **Industry Executives, Managers and Staff who support the government**

Workshop for Government and Industry Partners
Press is NOT Permitted to Permit Candid Discussion

CEUs and CLUs Credits
Awarded for Attendance

Team "Learn Together" Reduced Registration Fee

Workshop for Government and Industry Partners
Learn Together Team Rates:
Reduced Registration for Multiple Attendees from the Same Organization

Registration and Information:

www.potomacforum.org
Call: (703) 683-1613
info@PotomacForum.org

Sponsored by:
Potomac Forum, Ltd.
Founded in 1982 as a non-profit educational organization

Potomac Forum, Ltd is Proud to be:
Corporate Partner of
The Association of Government Accountants

Sustaining Partner
Association for Federal Information Resources Management
AFFIRM

Potomac Forum Direct Phone: (703) 683-1613

If this email is not of specific interest to you,
please forward to an associate.

Please DO NOT UNSUBSCRIBE from this
"Agile Development" mailing list.
Potomac Forum offers a wide variety of government related training events
which may be of interest to you in the future.
If you unsubscribe from this "Agile Development" list, you will
not receive future notices for "Agile Development" from this list.

Thank You.

This email was sent to: gunasekara.amanda@epa.gov

Go here to leave this mailing list or modify your email profile.
We respect your right to privacy. View our policy.

Potomac Forum, Ltd.

This email was sent by: **Potomac Forum, Ltd.**
400 North Washington Street , Alexandria , Virginia, 22314 , USA

Message

From: Mogler, Devin (Ernst) [Devin_Mogler@ernst.senate.gov]
Sent: 10/11/2017 11:38:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Palich, Christian [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=330ad62e158d43af93fcbbece930d21a-Palich, Chr]
Subject: RE: RVP

Thanks Mandy - appreciate the prompt response. Please keep us apprised of any breakthroughs in said trap-running.

Thanks also for your time on the call with Sen. Ernst today, as well as for connecting the Corn Oil One folks with your technical experts.

Devin Mogler | Legislative Assistant
U.S. Senator Joni Ernst | 111 Russell

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Wednesday, October 11, 2017 7:30 PM
To: Mogler, Devin (Ernst) <Devin_Mogler@ernst.senate.gov>
Cc: Palich, Christian <palich.christian@epa.gov>
Subject: Re: RVP

Hey Devin,
The preliminary analysis from our career team is that addressing this requires a statutory fix. However we have some novel arguments that we are running the traps on to gage legal viability.
Best,
Mandy

Sent from my iPhone

> On Oct 11, 2017, at 7:24 PM, Mogler, Devin (Ernst) <Devin_Mogler@ernst.senate.gov> wrote:
>
> Mandy,
> On today's call with Administrator Pruitt he mentioned to Senator Ernst that you are still "looking into" the RVP issue to see if you can address it administratively.
> I saw that he made similar comments yesterday in Kentucky.
> In our conversation on Sep 29 you indicated to our Chief and me that you had determined that you could not do administratively, and that it would take a statutory fix.
> Can you please confirm for me which is actually the case?
> Thanks,

Message

From: Useldinger, Kenny [kwu@rdotc.com]
Sent: 10/17/2017 7:10:14 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Baptist, Erik [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=10fc1b085ee14c6cb61db378356a1eb9-Baptist, Er]
CC: susan.alt@volvo.com
Subject: Glider Vehicles
Attachments: Glider Vehicles.pdf

Please consider our letter in regards to Glider Vehicles.

Thank you.

Kenneth Useldinger
President
RDO Truck Centers
RDO Truck Leasing
(701) 566-6546

RDO TRUCK CENTERS

The Honorable Scott Pruitt

Administrator

Environmental Protection Agency

Office of the Administrator 1101A

1200 Pennsylvania Avenue, NW

Washington, DC 20460

Cc:

Mandy Gunasekara, Senior Advisor to the Administrator (by email) Gunasekara.Mandy@epa.gov

Erik Baptist, Senior Deputy General Counsel (by email) baptist.erik@epa.gov

As a private business owner with operations in Fargo, Grand Forks, Bismarck, Dickinson and Williston, ND and Omaha, Lincoln, Lexington and Norfolk, NE I ask you to keep the volume cap on "glider vehicles" as written in the final Greenhouse Gas Phase 2 regulation.

Simply, glider vehicles are sold against us but with an unfair competitive advantage.

Today's new trucks meet US '10 emission levels by the installation of an expensive "chemical factory" behind the engine (the SCR and DPF). Because gliders vehicles don't meet the current emission standards, they avoid these expensive "chemical factories" that we, as conscientious business owners complying with EPA's strict emissions standards, provide our customers with the least amount of emissions possible.

Also, we are required to pay a 12% Federal excise tax on the sales price for every truck we sell. Glider Vehicles may not have to pay the excise tax. This tax is used to fund the Federal highway trust fund

which helps pay for our roads and bridges. So, we are at a 12% unfair price disadvantage and the vehicles we sell to build highway infrastructure is impacted as the fund is lessened with every glider vehicle sold.

I have lost sales to glider vehicles and it negatively impacts my business. I simply want a level playing field so that we can fairly compete.

Please feel free to contact me at kwu@rdotc.com.

Kenneth Useldinger

President

RDO Truck Centers

Clean Power Plan won't be missed: Delaware Voices

David T. Stevenson Published 9:14 a.m. ET Oct. 13, 2017 | Updated 10:29 a.m. ET Oct. 13, 2017, Wilmington News Journal, link: http://www.delawareonline.com/story/opinion/contributors/2017/10/13/clean-power-plan-wont-missed-delaware-voices/760983001/

Editor's note: This piece is a rebuttal to Wednesday's editorial, "Ending Clean Power Plan is bad news for Delaware."

Here's all you need to know about the Clean Power Plan (CPP) and its goal to reduce carbon dioxide emissions from electric generators in one sentence: The CPP is illegal, is another sign of our divided country, it wouldn't have a discernible impact on global warming, and the emission goals will probably be met without it.

Governments have granted territorial monopolies to companies that run the electric grid because it doesn't make sense to duplicate the incredible investment needed for competition. To protect consumers from these monopolies, in-state oversight has historically rested with individual state public utility commissions.

Federal law created the Federal Energy Regulatory Commission to oversee the interstate power grid. These organizations routinely balance price, reliability and environmental concerns.

The US Environmental Protection Agency (EPA), guided by an Executive Order from President Barack Obama, tried to take control of the entire electric grid with the CPP. Their singular purpose was to reduce carbon dioxide emissions with little care for electricity cost or reliability.

The EPA based the regulation on an obscure section of the Clean Air Act that was supposed to regulate individual power plants in rare cases when other sections didn't work. This section had only been narrowly used four times.

The section became the basis for not only regulating every power plant in the country, but also to force states to adopt carbon taxes, and to replace reliable base load power with expensive, intermittent wind and solar power.

Legal challenges based on the misuse of the Clean Air Act went as high as the Supreme Court which granted a stay in implementing the CPP based on the apparent validity of the legal arguments. Those challenges will continue for years, but with the current makeup of the Supreme Court, the CPP will likely be found to be illegal.

President Trump wrote an Executive Order requiring the EPA to review the legality of the CPP. The EPA found it should be repealed. The EPA will follow the required procedures to repeal the regulation and the task will probably not be complete until sometime in 2018.

The lawsuit against the CPP is supported by 27 states most of which were won by President Trump, and is opposed by 18 states most of which were won by Hillary Clinton. This is very much a red state versus blue state issue.

The states supporting the lawsuit against the CPP actually had more success reducing carbon dioxide emissions than the states opposing the lawsuit. According to US Energy Information Agency emission reports, and US Census population reports for 2007 and 2015, these states reduced emissions 1.8 times faster per person.

The 18 states supporting the CPP have already implemented most of the requirements in the plan. Those states consume 4 percent more power than they generate thus count on other states for electric generation. In effect, the states for the CPP exported 23 million metric tons of emissions to other states. The same states paid almost 4 cents per kilowatt-hour more for electricity, or 41 percent.

The states supporting the CPP, including Delaware, want to force the rest of the country to adopt the same losing policies. I guess misery loves company.

An argument might be made the misery is worth it if for the right environmental benefits, but the CPP doesn't deliver. The EPA developed a calculator to determine how incremental emission changes would impact global temperatures in the year 2100. The CPP goal is to reduce electric grid emissions by 32 percent between 2005 and 2030. That would only reduce global warming by 0.2 degrees centigrade, an amount that cannot be reliably measured.

The US Energy Information Agency just released national electric grid emissions data for 2016. Emissions are down 25 percent compared to a 22 percent reduction goal for 2020 in the CPP, and a 28 percent goal by 2025. The emission goals will likely be met without the CPP.

The Clean Power Plan will very likely be repealed, and won't be missed.

David T. Stevenson is director of the Center for Energy Competitiveness at the Caesar Rodney Institute. He served on the Trump administration's EPA transition team.

Message

From: Michael Whatley [MWhatley@hbwresources.com]
Sent: 10/19/2017 4:37:26 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Viator, Brad [BViator@eei.org]
Subject: EEI Member Meeting Invitation - October 25

Mandy –

Per our discussion, here is the information on the EEI Member Meeting next Wednesday.

The meeting is a collection of about 100 EEI member company state representatives as well as 50 or so federal representatives from many of those same companies. It is scheduled for October 25 at 830 AM, but we have a little flexibility that morning if you need to move the time around a bit.

I have copied Brad Viator from EEI, who is organizing the session and can provide any additional information that you may need.

Thanks.

Michael

Michael Whatley
HBW Resources
1666 K Street, NW, Suite 500
Washington, DC 20006
202-674-1750

Message

From: Stephen Fotis [scf@vnf.com]
Sent: 10/20/2017 1:36:44 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Janet Anderson [jma@vnf.com]
Subject: RE: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Thanks Mandy for your bio and making time to meet with LPPC. We look forward to seeing you next Tuesday morning.
Best,
Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
(202) 298-1908

This communication may contain information and/or metadata that is legally privileged, confidential or exempt from disclosure. If you are not the intended recipient, please do not read or review the content and/or metadata and do not disseminate, distribute or copy this communication. Anyone who receives this message in error should notify the sender immediately by telephone (202-298-1800) or by return e-mail and delete it from his or her computer.

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Thursday, October 19, 2017 2:52 PM
To: Stephen Fotis; Dominguez, Alexander
Cc: Janet Anderson
Subject: RE: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Following up from our call – attached is my bio. I look forward to seeing you next week.
Best,
Mandy

From: Stephen Fotis [mailto:scf@vnf.com]
Sent: Tuesday, September 26, 2017 3:25 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Janet Anderson <jma@vnf.com>
Subject: RE: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Alex – I would propose a 10 AM time slot for Mandy on October 24th. We can flexible on the timing if Mandy needs to adjust now or in the future. Talking in advance prior to the meeting is a great idea. I would propose anytime on Monday, October 16 at or after 10 AM.
Janet Anderson of our firm, who is copied on this email, would be joining me on this call.
Many thanks for your assistance! It is incredibly helpful and very much appreciated.
Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
(202) 298-1908

This communication may contain information and/or metadata that is legally privileged, confidential or exempt from disclosure. If you are not the intended recipient, please do not read or review the content and/or metadata and do not disseminate, distribute or copy this communication. Anyone who receives this message in error should notify the sender immediately by telephone (202-298-1800) or by return e-mail and delete it from his or her computer.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 26, 2017 12:41 PM
To: Stephen Fotis
Cc: Gunasekara, Mandy
Subject: RE: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Stephen,

Likewise, appreciate the call today and thank you for being flexible with the subject matter. I confirmed with Mandy and she is happy to speak on Tuesday, October 24th and a morning time would work as well – I've put a hold on her calendar so all set there. Aside from the agenda, if you could please let me know when you get a time pinned down. Lastly, if we could set up a brief call with Mandy and anyone else you think necessary from your end either the week of October 9th or the 16th we can go over any final details as she prepares. Looping in Mandy just so she is aware of our discussion.

Looking forward to it and anything else just let me know.

Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Stephen Fotis [mailto:scf@vnf.com]
Sent: Tuesday, September 26, 2017 12:04 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: FW: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Alex – Thanks for following up on the LPPC meeting on Tuesday, October 24. I have revised Mandy's agenda topic from focusing only on the CPP, to something more general. Right now the title of the topic is the "Pruitt EPA's Priorities and Activities on Key Air and Climate Regulatory Issues." We can further refine the topic title to accommodate Mandy. I will send a draft agenda of our meeting once it is ready for distribution.

Please let me know if you have questions.

Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
(202) 298-1908

This communication may contain information and/or metadata that is legally privileged, confidential or exempt from disclosure. If you are not the intended recipient, please do not read or review the content and/or metadata and do not

disseminate, distribute or copy this communication. Anyone who receives this message in error should notify the sender immediately by telephone (202-298-1800) or by return e-mail and delete it from his or her computer.

From: Stephen Fotis
Sent: Friday, September 22, 2017 10:50 AM
To: 'Gunasekara, Mandy (Gunasekara.Mandy@epa.gov)'; 'bolen.brittany@epa.gov'
Cc: 'John Di Stasio (john@lppc.org)'; Janet Anderson; 'Dominguez, Alexander'
Subject: RE: LPPC Follow-up on Addressing LPPC Envrionmental Task Force on Tuesday October 24

Mandy and Brittany – I'm following up on our request for you to address the LPPC Environmental Task Force at our upcoming meeting in WDC on Tuesday, October 24. As we discussed during our meeting in late August, LPPC can be a valuable resource for you and the Agency in providing useful policy and technical guidance on key environmental regulatory issues. One area where we'd like to work collaboratively with the Agency is in the development of a possible replacement rule to the Clean Power Plan. To that end, we would like to have one of you, or your staff, to address the members of the LPPC Environmental Task Force on the possibility of the Agency adopting a CPP replacement rule. We would propose to keep the format very informal, whereby you would make a few brief opening remarks and then answer questions that task force members may have. We also would propose to schedule something in the morning of October 24, but can be very flexible on the time in order to accommodate your schedules.
Many thanks,
Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
(202) 298-1908

This communication may contain information and/or metadata that is legally privileged, confidential or exempt from disclosure. If you are not the intended recipient, please do not read or review the content and/or metadata and do not disseminate, distribute or copy this communication. Anyone who receives this message in error should notify the sender immediately by telephone (202-298-1800) or by return e-mail and delete it from his or her computer.

From: Stephen Fotis
Sent: Wednesday, August 23, 2017 10:11 AM
To: Gunasekara, Mandy (Gunasekara.Mandy@epa.gov); bolen.brittany@epa.gov
Cc: John Di Stasio (john@lppc.org); Janet Anderson; Citta, Joe
Subject: LPPC Follow-up

Mandy and Brittany,
I want to thank both of you for making time on Monday to meet with John Di Stasio, Janet Anderson, and me regarding the Large Public Power Counsel (LPPC). We believe that LPPC can be a valuable resource for you and EPA in providing useful policy and technical guidance on key environmental regulatory issues. As discussed during our meeting, our mission is not to rehash past legal or policy issues, but rather to work collaboratively with you and your staff to ensure the effectiveness and workability of the regulatory proposals that the agency is advancing. To that end, I will be sending shortly to you by a separate email a short briefing paper on some of the air regulatory barriers to the electrification of the transportation sector under the Clean Air Act. We hope that this may be one area where we might be able to work together with you and your staff. In addition, we would like to get Tuesday, October 24 on your calendar. As we discussed during our meeting, the LPPC Environmental Task Force is meeting in WDC on this day and we would love for you (or other appropriate EPA person) to address the task force. We can be very flexible on timing as well as what you'd like to discuss – although I suspect a discussion on the CPP replacement rule may turn out to be very timely.
Best regards,
Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
(202) 298-1908

This communication may contain information and/or metadata that is legally privileged, confidential or exempt from disclosure. If you are not the intended recipient, please do not read or review the content and/or metadata and do not disseminate, distribute or copy this communication. Anyone who receives this message in error should notify the sender immediately by telephone (202-298-1800) or by return e-mail and delete it from his or her computer.

Message

From: Daniel Peterson [dpeterson@jamesmadison.org]
Sent: 10/24/2017 6:11:45 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Funes, Jason [jason_funes@ios.doi.gov]; Emhof, Jaryn [Jaryn.Emhof@mail.house.gov]; Brooks, Wes (Rubio) [Wes_Brooks@rubio.senate.gov]
Subject: FYI on CPP

The op-ed is now live on the Orlando Sentinel website. Below is the clip with the link to the article.

Orlando Sentinel

Commentary: EPA rides to the rescue of sustained electricity in Florida

http://www.orlandosentinel.com/opinion/os-ed-epa-rescues-electricity-coal-front-burner-20171023-story.html

Floridians, like all Americans, are accustomed to powering their lives with electricity that is abundantly available, reliable and affordable. The impact of recent hurricanes has reminded us how much our lives revolve around that all-important supply of power. Life without electricity means no air conditioning, no cellphones, no computers and no ability to pump gasoline — just to name a few. The absence of available, reliable and affordable electricity means inconvenience for all and economic hardship for many of Florida's most vulnerable.

For these reasons, U.S. Environmental Protection Agency Administrator Scott Pruitt and the Trump administration should be applauded for their decision to roll back the Clean Power Plan, an Obama administration mandate for electricity producing power plants to reduce CO2 emission by 30 percent by 2030. This unsustainable plan was nothing more than a regulatory way to get around Congress' refusal to adopt a "cap and trade" scheme in 2010. In effect, it was a takeover of our nation's electrical power grid via federal regulation, something that has always been under the authority of the states.

With this action, Pruitt is saving the country from implementation of the CPP, which would be devastating for consumers and our nation. The plan would have forced Florida and 46 other states to systematically limit the kind of power plants we rely on for our power and force us to shift to other energy sources — ones that as yet remain as untested as they are unreliable.

While the EPA's estimates have been repeatedly shown to underestimate the cost of the CPP and exaggerate the benefits, an independent study has found that Florida's electricity prices face an 11 percent average annual increase, with a peak year increase of 15 percent.

As summer turns to fall and Floridians look ahead to the holiday season, investing in smart technologies can help you take control of your energy use and your bill.

An annual update to the Energy Cost Impacts on American Families study indicates that, indeed, Americans spend a significant amount of their incomes on energy. Data compiled from the U.S. Bureau of Labor Statistics, U.S. Census Bureau, and U.S. Energy Information Administration show that 40 percent of American families (51 million households) take home an average of $1,643 each month and spend 17 percent of that on energy bills.

The news is even grimmer for the most vulnerable Americans. According to the same study, the poorest 25 million families spend a whopping 22 percent of their monthly income on electricity and gas. American families should not have to balance their ability to keep the lights on against cutting back on other basic necessities. For many families, though, CPP would have made that stark choice ever closer to becoming a reality.

This disturbing news clashes with the fact that the United States is home to some of the most abundant energy resources in the world. Our country is quickly becoming a major producer of oil and natural gas. Coal, long a staple in the national energy mix, has seen substantial investments, totaling upwards of $122 billion by the end of the year, to make its use cleaner. Since the 1970s, coal has become 92 percent cleaner to use.

And yet, despite the good news, national average electricity prices have continued to creep up, consuming more and more of family budgets. Since 2005, prices have climbed by 33 percent when adjusted for inflation.

What drives these prices ever upward? There are many factors, but some of the blame can rightly be placed on the shoulders of the politicians and bureaucrats in our nation's capital. Unelected bureaucrats at the EPA have been incredibly busy in recent years churning out regulations that have cost the economy and consumers billions of dollars. CPP is perhaps the most visible and devastating.

In the battle to protect America's energy resources, Florida Attorney General Pam Bondi, along with other states' attorneys general, pushed back against federal overreach by suing the EPA over the CPP. Very much to their credit, they secured an unprecedented delay from the Supreme Court while they work for a total overturn. Now, that day is here thanks to the leadership of Pruitt and the Trump administration.

Ensuring available, reliable and affordable electricity should be of utmost concern to policymakers, both in Washington and in Tallahassee. The decision to roll back CPP makes providing such electricity sustainable, and that helps us all. Today, when you flip on your lights switches or adjust the thermostat on your air conditioning, remember to say, "Thank you."

Dan Peterson is the director for the Center for Property Rights at The James Madison Institute.

Daniel Peterson

Director: Center for Property Rights | The James Madison Institute

dpeterson@jamesmadison.org | **c.** 407-758-2491

The Columns | 100 N. Duval St. | Tallahassee, FL 32301

or 303 Valley Edge Drive | Clermont, FL 34715

WATCH JMI's 30th Anniversary highlight video featuring our work across the Sunshine State since 1987.

Connect with us! Sign up for JMI News | Follow JMI on Twitter | Like JMI on Faceboo

"Property must be secured or liberty cannot exist." John Adams, 1790

Message

From: Wilcox, Jahan [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=88FD588E97D3405D869BCAE98D391984-WILCOX, JAH]
Sent: 10/10/2017 4:22:03 PM
To: Eilperin, Juliet [Juliet.Eilperin@washpost.com]
CC: Bowman, Liz [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=c3d4d94d3e4b4b1f80904056703ebc80-Bowman, Eli]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: EPA Proposes Repeal Of Clean Power Plan - Preview

Adding Liz and Mandy.

From: Eilperin, Juliet [mailto:Juliet.Eilperin@washpost.com]
Sent: Tuesday, October 10, 2017 12:20 PM
To: Wilcox, Jahan <wilcox.jahan@epa.gov>
Subject: RE: EPA Proposes Repeal Of Clean Power Plan - Preview

Hey Jahan, can you send me a link to the Federal Register notice, by chance? Thanks.

From: Wilcox, Jahan [mailto:wilcox.jahan@epa.gov]
Sent: Tuesday, October 10, 2017 12:05 PM
To: Eilperin, Juliet <Juliet.Eilperin@washpost.com>; Hohmann, James <James.Hohmann@washpost.com>
Cc: Bowman, Liz <Bowman.Liz@epa.gov>
Subject: FW: EPA Proposes Repeal Of Clean Power Plan - Preview

Off-the-record …

For your knowledge we are sharing this press release with a handful of folks. You are welcome to report on the press release right now – there is no embargo – but we kindly ask that you do not tweet any images of the release until **today at 12:30 PM EDT**, which is when it will be sent to our full list.

Jahan

From: EPA Press Office [mailto:press=epa.gov@cmail19.com] **On Behalf Of** EPA Press Office
Sent: Tuesday, October 10, 2017 12:00 PM
To: Wilcox, Jahan <wilcox.jahan@epa.gov>
Subject: EPA Proposes Repeal Of Clean Power Plan - Preview

CONTACT: press@epa.gov

EPA Takes Another Step To Advance President T
First Strategy, Proposes Repeal Of "Clean P

WASHINGTON (October 10, 2017) - Today, U.S. Environmental Pro
Administrator Scott Pruitt issued a Notice of Proposed Rulemaking
repeal the so-called "Clean Power Plan (CPP)." After reviewing th
proposed to determine that the Obama-era regulation exceeds the
authority. Repealing the CPP will also facilitate the development
resources and reduce unnecessary regulatory burdens associated v
of those resources, in keeping with the principles established in Pr
Executive Order on Energy Independence.

"The Obama administration pushed the bounds of their authority s
that the Supreme Court issued a historic stay of the rule, preventi
effects to be imposed on the American people while the rule is be
court," **said EPA Administrator Scott Pruitt**. "We are committed
of the Obama administration by cleaning the regulatory slate. An
be done carefully, properly, and with humility, by listening to all
rule."

CPP Appears to be Inconsistent with the Clean Air Act

The CPP, issued by the Obama administration, was premised on a
view of Agency authority that the Trump administration now prop
inconsistent with the Clean Air Act. In fact, the CPP was put on h
when the U.S. Supreme Court issued an unprecedented, historic st

"EPA will respect the limits of statutory authority. The CPP ignor
and eroded longstanding and important partnerships that are a ne
achieving positive environmental outcomes. We can now assess wh
regulatory action is warranted; and, if so, what is the most approp
consistent with the Clean Air Act and principles of cooperative fed
Administrator Pruitt.

The CPP was issued pursuant to a novel and expansive view of aut
111 of the Clean Air Act (CAA). The CPP required regulated entiti
"outside the fence line." Traditionally, EPA Section 111 rules were
that could be applied to, for, and at a particular facility, also refe
fence line" measures. Prior to the CPP being issued, every single S
books, including a handful of existing source rules and around 100
obeyed this limit. As the CPP departed from this traditional limit c
under an "inside the fence line" interpretation, EPA is proposing t

EPA has now sent the NPRM to the Federal Register for publicatior
the public will have 60 days to submit comments.

The repeal package includes:

1. The "preamble," which lays out the proposed legal interpreta
implications, and a summary of the cost-benefits analysis of th
and
2. The "Regulatory Impact Analysis (RIA)," an in-depth cost-bene

CPP Repeal Saves up to $33 Billion in Avoided Costs in 2030

The proposed repeal both examines the Obama administration's c
well as provides insights to support an updated analysis of the env
and economic effects of the proposed repeal. The Trump administ
proposed repeal could provide up to $33 billion in avoided compli

The previous administration's estimates and analysis of these cost
multiple areas, highly uncertain and/or controversial. Specific are
and/or uncertainty in the Obama administration's analysis of CPP

- **Domestic versus global climate benefits**: The previous admin
U.S. costs to an estimate of supposed global benefits, and fail
established economic procedures in estimating those benefits.

- **"Co-benefits" from non-greenhouse-gas pollutants**: The Ob
relied heavily on reductions in other pollutants emitted by pov

hiding the true net cost of the CPP by claiming benefits from r
that had nothing to do with the rule's stated purpose.

- **Energy cost and savings accounting**: The Obama administrati
efficiency" results of their rule as an avoided cost, resulting in
considerably lower than it would have been if they used the ap
considering these effects as benefits, rather than subtracting t
the Obama administration used the Office of Management and
requirements and accounted cost and savings accordingly, it w
more accurate accounting of the total cost of the CPP.

In this proposed repeal and its accompanying technical documents
is, in a robust, open, and transparent way, presenting a wide rang
to the public.

As part of the notice-and-comment process for this proposed repe
this analysis and inform the public, as necessary, to get feedback
other information. The final action on this proposed repeal will ac
this ongoing work.

Forthcoming is an Advanced Notice of Proposed Rulemaking (ANPR
reflective of a thoughtful and responsible approach to regulatory a
the authority provided by the statute.

"With this action, the Trump administration is respecting states' r
transparency into how we protect our environment," **said Adminis**

Background:
On March 28, President Trump signed an Executive Order on Energ
establishing a national policy in favor of energy independence, ec
the rule of law. The purpose of the Executive Order (EO) is to faci
of U.S. energy resources and to reduce unnecessary regulatory bur
the development of those resources. That same day, EPA Administ
signed four Federal Register notices in response to the EO, includi
announcement of review of the Clean Power Plan. After substanti
has proposed to determine that the Clean Power Plan (CPP) must

Visit The EPA's Newsroom

[usenvironmentalprotectionagency.cmail19.com] [usenvironmentalprotectionagency.cmail19.com] [usenvironmental

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue Northwest
Washington, D.C. 20004

Unsubscribe[usenvironmentalprotectionagency.cmail19.com]

Message

From: Desmarie Waterhouse [dwaterhouse@publicpower.org]
Sent: 10/20/2017 11:39:19 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Thank you!

Mandy:

Thank you so much for coming to speak to our CEOs yesterday on EPA's climate and air agenda. It was a really informative presentation and I heard a ton of great feedback from the members, who are very pleased with the new direction of the agency under Administrator Pruitt. The focus on cooperative federalism really resonated with the task force.

I really appreciate you making the time for this. I know how busy it has been for you since joining EPA. If there is anything we can help you with going forward, please let me know.

Have a great weekend!

Des

Desmarie M. Waterhouse
Vice President of Government Relations & Counsel
American Public Power Association
2451 Crystal Dr., Ste. 1000
Arlington, VA 22202
202-467-2930 (w)
703-665-9182 (c)

Message

From: Courtney Cook [CCook@alec.org]
Sent: 10/18/2017 3:24:24 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Look who is joining us

The Honorable Ken Cuccinelli

Learn from former Virginia Attorney General Ken Cuccinellie about how states can address the growing national debt. Grab a hearty breakfast, and be a part of the solution!

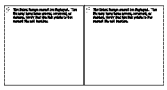
Have you made your hotel reservation?

Book your room now as our discounted rate of $209 is selling out **QUICKLY!**

Only a few days left to have your staff take part in the Legislative Staff Fellowship. Has your staff applied?

The ALEC Legislative Staff Fellowship consists of a series of online educational sessions and a three-day program of training and networking with legislative staff members from around the country at the 2017 States and Nation Policy Summit. The purpose of the training is to promote professional development and philosophical ideals throughout their careers as legislative staffers.

Questions on applying? Contact **Lacey White** for more information.



This message was sent to **gunasekara.mandy@epa.gov** from **CCook@alec.org**

Courtney Cook
ALEC
2900 Crystal Drive, 6th Floor
Arlington, VA 22202

Unsubscribe

Message

From: Holland, Luke (Inhofe) [Luke_Holland@inhofe.senate.gov]
Sent: 10/17/2017 6:43:28 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Wright, Jennie (Inhofe) [Jennie_Wright@inhofe.senate.gov]
Subject: FW: Telegraph Herald: Grassley willing to hold up EPA nominations over Renewable Fuel Standard proposal

Fun.

From: Barfield, Blake [mailto:Blake.Barfield@HollyFrontier.com]
Sent: Tuesday, October 17, 2017 2:43 PM
To: Wright, Jennie (Inhofe) <Jennie_Wright@inhofe.senate.gov>; Holland, Luke (Inhofe) <Luke_Holland@inhofe.senate.gov>
Subject: Telegraph Herald: Grassley willing to hold up EPA nominations over Renewable Fuel Standard proposal

Telegraph Herald
Grassley willing to hold up EPA nominations over Renewable Fuel Standard proposal
By Thomas J. Barton
17 October 2017

U.S. Sen. Charles Grassley, R-Iowa, today said he is willing to hold up Environmental Protection Agency nominees should the Trump administration fail to uphold its pledge to support biofuels and a strong Renewable Fuel Standard.

EPA Administrator Scott Pruitt is scheduled to meet today with Grassley, Sen. Joni Ernst, R-Iowa, and other senators from Midwestern states.

"Hold up EPA nominees," Grassley said during a conference call this morning in response to a question of what leverage he planned to use should the administration plan to move forward with a proposal to lower the RFS. "I think there's plenty of senators who would do that."

Advocates for the renewable fuels industry, including Grassley and Ernst, have been upset since the EPA raised the idea last month that it might lower required levels of advanced biofuels for 2018 -- and that it could count exports of traditional ethanol toward meeting the mandate.

Iowa Gov. Kim Reynolds sent a letter to President Donald Trump on Monday expressing her "deep concern" about the direction EPA appears to be taking on the Renewable Fuel Standard.

Kansas Gov. Sam Brownback, Missouri Gov. Eric Greitens and South Dakota Gov. Dennis Daugaard also signed on to Reynolds' letter.

"Two weeks ago, the EPA requested comment on whether it should further reduce the total, advanced and biomass-based diesel volumes beyond the recently proposed (and ill-advised) cuts to the 2019-19 RFS volumes," Reynolds said in a press release. "This action is concerning and runs counter to the president's repeated commitment to the RFS and rural America. The stated purpose of the RFS is to grow demand for biofuels — to push the industry to innovate — and I encourage the EPA to remember that when finalizing the volume levels.

Reynolds argues the RFS has "revitalized our rural communities, bringing jobs and hope."

The standard, passed and signed into law in 2005, requires increasing volumes of renewable fuels to be blended into the U.S. fuel supply.

Iowa is the nation's top biodiesel producer, and the renewable fuels industry in the state supports more than 43,000 jobs and generates $2.3 billion of income for Iowans.

Trump pledged during the 2016 election campaign that he would support renewable fuels. But Pruitt, who is a former attorney general of Oklahoma, has been a critic of the RFS in the past.

Earlier this year, before Pruitt was confirmed, Grassley and Ernst said they had been reassured after meeting with him that he would follow the law.

Since, then, Grassley said he has gotten a sense "of an impractical position on (Pruitt's) part that he can thread the needle between keeping the president's promise for ... supporting the biofuels industry, as he promised, and also satisfy the desires of a lot of inefficient refineries that are mad about (obtaining expensive credits used to meet an EPA-specified Renewable Volume Obligation). And he thinks he can satisfy both."

CONFIDENTIALITY NOTICE: This e-mail, and any attachments, may contain information that is privileged and confidential.If you received this message in error, please advise the sender immediately by reply e-mail and do not retain any paper or electronic copies of this message or any attachments.Unless expressly stated, nothing contained in this message should be construed as a digital or electronic signature or a commitment to a binding agreement.

Message

From: Michael.McAdams@hklaw.com [Michael.McAdams@hklaw.com]
Sent: 10/13/2017 7:08:09 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: bethviola@mac.com
Subject: Letter to the President, and Administrator Pruitt
Attachments: ABFA NODA Letter - Final.pdf

Ms. Gunasekara: On behalf of my undersigned membership we have forwarded the attached letter to The White House and copied the Administrator. The letter expresses our concerns on the released NODA document discussing the potential lowering of the proposed RVO's. Obviously, we are preparing comments in response to the document and look forward to any appropriate opportunity to discuss our concerns surrounding the potential options which were discussed in the document. Thank you for your consideration of our concerns.

Michael McAdams | Holland & Knight
President, ABFA
Sr Policy Advisor
Holland & Knight LLP
800 17th Street N.W., Suite 1100 | Washington, DC 20006
Phone 202.469.5140 | Fax 202.955.5564
michael.mcadams@hklaw.com | www.hklaw.com

NOTE: This e-mail is from a law firm, Holland & Knight LLP ("H&K"), and is intended solely for the use of the individual(s) to whom it is addressed. If you believe you received this e-mail in error, please notify the sender immediately, delete the e-mail from your computer and do not copy or disclose it to anyone else. If you are not an existing client of H&K, do not construe anything in this e-mail to make you a client unless it contains a specific statement to that effect and do not disclose anything to H&K in reply that you expect it to hold in confidence. If you properly received this e-mail as a client, co-counsel or retained expert of H&K, you should maintain its contents in confidence in order to preserve the attorney-client or work product privilege that may be available to protect confidentiality.

Advanced Biofuels Association

October 13, 2017

President Donald Trump
The White House
1600 Pennsylvania Ave, NW
Washington, DC 20500

Dear Mr. President:

We write today to express our strong opposition to the October 4th Notice of Data Availability (NODA) from the Environmental Protection Agency (EPA), which requests comments on "potential options for reductions" on the EPA's proposed 2018 Renewable Volume Obligation mandates (RVOs) under the Renewable Fuel Standard (RFS) program.

As domestic and international producers, marketers, and distributors of over 12 billion gallons annually of renewable fuels, including 4 billion gallons of biodiesel and renewable diesel, we have grave concerns about the market and consumer impacts of this NODA. We believe that this proposal will ultimately raise the price of fuel for American consumers while reducing the incentive to invest in growing America's capacity to produce, blend, and distribute innovative renewable fuels.

Specifically, we oppose the proposals in the NODA on three grounds.

First, the NODA undercuts the basic intent of the RFS program by reducing the annual mandates for advanced RVO pools lower than previous years' mandates and lower than available domestic supply. We believe Congress intended the RFS to *increase* American consumption of renewable fuel in order to reduce our dependence on foreign oil and greenhouse gas (GHG) emissions –instead, EPA is reducing the mandates below available domestic supply. Such reductions not only undercut investments which have already been made by fuel producers and blenders, but would also discourage future investments in advanced biofuels. In addition, the proposed NODA would replace advanced biofuels delivering 50% GHG reductions with fuels delivering less than 20% reductions.

In particular, further reducing the biomass-based diesel pool has no grounds. EPA itself predicts that 2.9 billion gallons will be available domestically in 2018, yet the current proposal leaves the RVO flat at 2.1 billion gallons and this NODA threatens to drop the mandate down as low as one billion gallons.[1] Given that the domestic supply of biomass-based diesel has exceeded the annual RVO mandates for each of the last three years, we believe such a proposal to drop these mandates is fundamentally misguided.

Second, EPA justifies this decrease by inventing its own definition of "domestic supply" that is directly contrary to the federal court's interpretation of the RFS, reversing the direction and application of the statute since the inception of the RFS program. The case *Americans for Clean Energy, et al. v. Environmental Protection Agency and E. Scott Pruitt,*

[1] "Proposed RFS Standards for 2018 and Biomass-Based Diesel for 2019," 82 Fed. Reg 34239, July 21, 2017.

Administrator, decided on July 28, 2017 by the U.S. Court of Appeals for the District of Columbia Circuit, specifically states,

> The Renewable Fuel Program requires that increasing volumes of renewable fuel be introduced into the Nation's supply of transportation fuel each year. Congress enacted those requirements in order to "move the United States toward greater energy independence and security" and "increase the production of clean renewable fuels.[2]

Furthermore, the Court states,

> To date, EPA has applied the renewable fuel obligations only to refiners and importers of fuel – not to blenders...by requiring upstream market participants such as refiners and importers to introduce increasing volumes of renewable fuel into the transportation fuel supply, Congress intended the Renewable Fuel Program to be a "market forcing policy" that would create "'demand pressure' to increase consumption" of renewable fuel.[3]

EPA's NODA clearly violates the basic tenets of the RFS program by reducing the demand pressure in spite of adequate and increasing domestic supply.

Third, the NODA speculates on overall market conditions and trends governed by forces well beyond EPA's jurisdiction. In our opinion, this demonstrates a fundamental misunderstanding by EPA of how the biofuels and RIN markets actually operate.

While EPA states that domestic supply may be reduced in response to both the expiration of the biodiesel blender's tax credit and a potential countervailing duty placed on Argentinian and Indonesian fuels, we believe that neither of these events will cause meaningful decreases in available domestic supply. In the first six months of 2017, without the tax credit in place, over 1.6 billion gallons were produced. We are on track to exceed the 2.1 billion gallon mandate originally proposed, let alone the reduced volumes EPA is currently considering. Moreover, the market is already adjusting to increase U.S. production and increase production from Canada and Europe in response to the Department of Commerce case. Already, cargos are landing in U.S. ports from U.S. companies' overseas production facilities. This competition in the marketplace, combined with the favorable logistics and pricing, will continue driving down costs for consumers at the pump.

Furthermore, the nesting function of the RFS was designed such that when the biomass-based diesel pool actually exceeded the 2016 RFS mandate, the market naturally lowered the overall RIN cost and made compliance cheaper for merchant refiners in need of RINs. The RFS program's structure allows for market correction—and this competitive, free market is functioning at maximum economic efficiency without EPA's interference.

Mr. President, we believe EPA's proposal to reduce the annual mandates under the RFS will have negative impacts on producers, marketers, and consumers alike. Moreover, the proposal is absolutely unwarranted given the performance of the advanced biofuels industry

---

[2] *Americans for Clean Energy et al. v. Environmental Protection Agency,* D.C. Cir. No. 16-1005, July 28, 2017, p. 5.
[3] *Ibid,* p. 21.

in recent years. We oppose the EPA's proposal and urge you to ensure the Administration's support for increasing the volumes of advanced biofuels used across America.

Sincerely,

AltAir Fuels
Fulcrum BIOENERGY
oberon FUELS
AMERIgreen Energy
gevo
pilot FLYING J
APROBIO Associação dos Produtores de Biodiesel do Brasil
RES KAIDI
biox
LDC Louis Dreyfus Company
SpecOil
bp
Loves Travel Stops
TARGRAY
BSBIOS RENEWABLE ENERGY
Trillium CNG
MUSKET
Cargill
VIESEL
ecoengineers
NESTE
Vitol
ENSYN
NuFuels
wilmar

cc: EPA Administrator Scott Pruitt

Message

From: Hilary Moffett [moffetth@api.org]
Sent: 10/12/2017 2:26:18 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Ozone Implementation Assistance

Hi Mandy,

Hope you're doing well. Congratulations on such a big week with CPP!

I wanted to reach out about a meeting request for ozone implementation assistance. I know the Administrator has talked about looking at the Exceptional Events rule and possibly other rules that could help with implementation of the ozone standards. We are heavily invested in this conversation and would welcome the chance to come in and discuss specific ways that we believe EPA could address implementation issues.

Do you have time at the end of the month for a meeting with API members?

Thanks,
Hilary

Hilary Moffett
Director, Federal Relations
American Petroleum Institute
202-682-8040 (desk)
612-710-8696 (cell)
MoffettH@api.org

Message

From: Larry Schafer [lschafer@playmakerstrategies.com]
Sent: 10/4/2017 5:20:37 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: NPRM on RIN exports

Hey Mandy

Hearing an NPRM on the RIN export idea is possibly slated for release next week.

Any truth to that rumor?

Larry Schafer
Playmaker Strategies
202.997.8072

Message

From: George Cooper [gcooper@forbes-tate.com]
Sent: 10/23/2017 4:10:13 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Jeff Sadosky [jsadosky@forbes-tate.com]
Subject: Re: NMMA Meeting Request

Thanks Alex very much for getting back to me – will have answer for you shortly.
-G

From: "Dominguez, Alexander" <dominguez.alexander@epa.gov>
Date: Monday, October 23, 2017 at 12:06 PM
To: George Cooper <gcooper@forbes-tate.com>, "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Cc: Jeff Sadosky <jsadosky@forbes-tate.com>
Subject: RE: NMMA Meeting Request

George – Mandy in unfortunately unable to meet this week. The soonest availability would be for a call on Friday, November 10th at 11:30AM or 2:00PM EDT. Please let me know if either of those work.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: George Cooper [mailto:gcooper@forbes-tate.com]
Sent: Monday, October 23, 2017 10:19 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Jeff Sadosky <jsadosky@forbes-tate.com>
Subject: Re: NMMA Meeting Request
Importance: High

Mandy and Alex I am checking back to see if we might be able to pull together a meeting for Wednesday afternoon or Thursday. Since sending this request last week NMMA has taken a look at the letter from Administrator Pruitt to the corn belt senators and in particular the paragraph regarding E15. We of course have members asking about this and so are even more anxious to visit with you and/or appropriate colleagues about the huge stakes at hand when it comes to putting E15 into market during the most popular summer boating months.
NMMA President Thom Dammrich is in town on Wednesday and Thursday so I am hoping we can find a time that works.
Thank you both,
George Cooper

From: George Cooper <gcooper@forbes-tate.com>
Date: Thursday, October 19, 2017 at 3:30 PM
To: "Gunasekara.Mandy@epa.gov" <Gunasekara.Mandy@epa.gov>, "dominguez.alexander@epa.gov" <dominguez.alexander@epa.gov>
Subject: NMMA Meeting Request

Mandy and Alex you met with several members of the National Marine Manufacturers Association earlier this year – as you may recall Administrator Pruitt was under the weather but ended up joining us for some of the productive discussion. We covered several subjects that day, spending some time on ethanol and E15 in particular. Wondering if some NMMA reps can come in to see you and/or any of your colleagues you think appropriate to expand on our recent thinking regarding E15 and a few other biofuel related matters. Looking at Wednesday or Thursday next week if possible.
Thank you very much!
George

George Cooper
Forbes Tate Partners
777 6th Street, NW, 8th Floor
Washington, DC 20001
O: 202-638-0125
C: 703-371-5572
F: 202-638-0115
www.forbes-tate.com

FORBES | TATE
PARTNERS

Message

From: Jack Barrow [jack.barrow@btr.energy]
Sent: 10/6/2017 11:08:14 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: Jim Lemon [jim.lemon@btr.energy]; Michael Lemon [mlemon@btr.energy]
Subject: Re: Thank you and follow-up
Attachments: RFS -- Electric Pathway Letter (House).pdf

Mandy, Justin, Alex -- I hope you're all doing well and have fun plans for the weekend! Just wanted to follow-up with you on our meeting from a few weeks ago and provide a quick update.

This morning, Congressmen Chris Collins and Peter Welch co-lead a letter to the Administrator endorsing the electric pathway and encouraging quick action on the opportunity. I'm sure the letter is making its way through Congressional affairs now, but I thought I'd share it with you for reference (attached).

I know you're inundated, but if you do have time in October to meet again or take a call, we'd certainly like to talk more about next steps and how we can help move this forward.

Let me know what's best.

Thanks,
Jack

On Fri, Sep 8, 2017 at 3:48 PM, Jack Barrow <jack.barrow@btr.energy> wrote:

Mandy, Justin, Alex -- thank you all for your time! We truly appreciate the chance to speak directly to the decision-makers and hope we were helpful.

I've attached the "Guidance Document" we came up with that synthesizes all of the issues we've identified through our work with EPA over the last three years and how best to deal with them. (Attached as a Word doc so you can edit/ work with it). We think this is complete and addresses the outstanding issues that need to be addressed before implementing the pathway.

If there's anything else we can do to make this easier for your teams or move the process along, please give us a shout. We know you're swamped, but if we can get anything done on our application in the next few months, there'd be some mighty happy farmers, big and small, in the dairy industry in particular.

Either way, keep us posted on your thoughts after you've processed.

Thanks again for your help.

Best wishes,
Jack

--
Jack Barrow
Co-Founder | BTR Energy
(952) 380-7512

--
Jack Barrow
Co-Founder | BTR Energy
(952) 380-7512

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/12/2017 1:59:32 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Draft Regional Haze SIP and Entergy White Bluff Administrative Orders

I sure will. Stay caffeinated.

Sent from my iPad

On Oct 11, 2017, at 4:49 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

Thanks Stuart. Tomorrow is crazy, but try my cell: Personal Phone / Ex. 6

From: Spencer, Stuart [mailto:SPENCER@adeq.state.ar.us]
Sent: Wednesday, October 11, 2017 5:35 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Draft Regional Haze SIP and Entergy White Bluff Administrative Orders

Mandy,

I hope all is well! We've been having computer issues here at ADEQ for the last two days, but I wanted to go ahead and get the attached docs to you. I'll call you tomorrow to follow up and further explain.

Thanks!

Stuart

Sent from my iPad

Begin forwarded message:

From: "Treece, Tricia" <treecep@adeq.state.ar.us>
To: "Spencer, Stuart" <SPENCER@adeq.state.ar.us>
Subject: FW: Revisions to SIP and AO

Here are the most recent copies of the SIP docs and the language suggestions I sent in the other email are below. I didn't add them to the Word docs since I don't have Microsoft Office on my personal computer.

In the August 18, 2017 updated BART analysis for White Bluff, Entergy amortized costs based on their proposal regarding (changes in) coal-fired operations. The August 18, 2017 analysis redacted Entergy's proposed date (to enact these changes); however, the cost-effectiveness for Dry FGD included in the August 18, 2017 analysis corresponds to Dry FGD cost-effectiveness estimates provided in Entergy's April 21, 2017 letter based on a seven-year to eight-year remaining useful life scenario. In comments on the AR RH FIP, Entergy also proposed dates as part of a "multi-unit plan to improve visibility and to better

manage generation assets for reliability and costs." In those comments, Entergy proposed to "take an enforceable limit" regarding their (planned changes in) coal-fired operations.

Under the guidelines for BART determinations, the remaining useful life calculation should begin on "the date that controls will be put in place" (compliance date) and ending on "the date the facility permanently stops operations." Based on the controls evaluated, the compliance date for controls would be as expeditiously as practicable, but in no event later than five years after approval of the SIP. The guidelines further specify that the permanent operations cessation date should be "assured by a federally- or State-enforceable restriction preventing further operation." Therefore, ADEQ agrees that Entergy's cost-effectiveness calculations are reasonable based on a remaining useful life of seven years and Entergy's proposal to take an enforceable limit regarding (the timing of their planned changes in) coal-fired operations.

From: Spencer, Stuart
Sent: Tuesday, October 10, 2017 11:11 AM
To: Montgomery, William; Treece, Tricia
Subject: Revisions to SIP and AO

I revised remaining useful life language.

Stuart Spencer
Associate Director- Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
Ph. # (501) 682-0750
Fax # (501) 682-0880
E-mail: SPENCER@adeq.state.ar.us
Web: http://www.adeq.state.ar.us<http://www.adeq.state.ar.us/>

[cid:image001.jpg@01D341B8.7BABF050]

This e-mail and any files transmitted with it are the property of the Arkansas Department of Environmental Quality, and are intended solely for the use of the individual or entity to whom this email is addressed. If you are not the named recipient(s) or otherwise have reason to believe that you have received this message in error, please notify the sender at (501) 682-0750 and delete this message immediately from your computer. Any other use, retention, dissemination, forwarding, printing or copying of this email is strictly prohibited.

Message

From: Baptist, Erik [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=10FC1B085EE14C6CB61DB378356A1EB9-BAPTIST, ER]
Sent: 10/13/2017 5:46:06 PM
To: Dorri Gibson [dgibson@tecequipment.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: EPA Letter

Thank you, Dorri.

Erik Baptist
Senior Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
1200 Pennsyvlania Ave., NW
Washington, DC 20460
(202) 564-1689
baptist.erik@epa.gov

From: Dorri Gibson [mailto:dgibson@tecequipment.com]
Sent: Friday, October 13, 2017 1:24 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Baptist, Erik <baptist.erik@epa.gov>
Subject: EPA Letter
Importance: High

Good Morning To Whom it May Concern:

Please open attachment: From David Thompson, President/CEO of TEC Equipment, Inc.

Thank you,

Dorri Gibson
Executive Assistant
TEC Equipment
Office: 503.247.4601
dgibson@tecequipment.com

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 10/3/2017 8:47:52 PM
To: Myron Ebell [Myron.Ebell@cei.org]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Bolen, Brittany [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=31e872a691114372b5a6a88482a66e48-Bolen, Brit]
Subject: RE: Scheduling a meeting with a visitor

Myron – Let's do tomorrow, Oct. 4th, at 5:15PM.

Location: 1200 Pennsylvania Avenue, NW.

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg

EPA Contact: For an escort from Security to the meeting call 202-578-5985 or 202-564-3164

Anything else please let me know. Looking forward to it.

Best,

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Myron Ebell [mailto:Myron.Ebell@cei.org]
Sent: Tuesday, October 3, 2017 2:47 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Subject: RE: Scheduling a meeting with a visitor

Dear Alex, Later on Wednesday is better if that suits you. If it's late enough, we can meet for drinks! Thursday afternoon is out. Thanks, Myron.

Myron Ebell
Director, Center for Energy and Environment
Competitive Enterprise Institute
1310 L Street, N. W., Seventh Floor
Washington, DC 20005, USA
Tel direct: (202) 331-2256
Tel mobile: (202) 320-6685
E-mail: Myron.Ebell@cei.org
Stop continental drift!

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, October 3, 2017 2:44 PM
To: Myron Ebell <Myron.Ebell@cei.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Subject: RE: Scheduling a meeting with a visitor

Myron - The earliest Mandy could do tomorrow is at 5:15 or Thursday at 5:00. Let me know if any of these work. If not I am happy to facilitate a call.

Alex

From: Myron Ebell [mailto:Myron.Ebell@cei.org]
Sent: Tuesday, October 3, 2017 2:37 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Scheduling a meeting with a visitor

Dear Brittany and Mandy, Do you still have any time to get together with Owen Paterson and me? He's meeting Lamar Smith at 9:30 on Thursday and someone in the OEOB at 10:30 and then has to be at Heritage before 12 noon. Tomorrow—Wednesday—afternoon, the only meeting he has after lunch that can't be moved is with Inhofe at 3 PM. Or you're welcome to come to lunch at CEI, where you'll see many friends. By the way, do you and Ryan know about the Weyrich Awards dinner on the 17th? If not, I'll tell you over the phone or in person. Yours, Myron

Myron Ebell
Director, Center for Energy and Environment
Competitive Enterprise Institute
1310 L Street, N. W., Seventh Floor
Washington, DC 20005, USA
Tel direct: (202) 331-2256
Tel mobile: (202) 320-6685
E-mail: Myron.Ebell@cei.org
Stop continental drift!

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Thursday, September 28, 2017 12:57 PM
To: Myron Ebell <Myron.Ebell@cei.org>; Bolen, Brittany <bolen.brittany@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Scheduling a meeting with a visitor

Myron,
Great to hear from you. For me, the afternoon of the 4th is somewhat flexible. I'll be at the nomination hearing so hopefully that will wrap up by early afternoon and I'd be happy to meet with Owen. Is it best for use to coordinate with you or should we reach out to him?

I've also cc'd Alex who can firm up all the logistics from our end.
Best,
Mandy

From: Myron Ebell [mailto:Myron.Ebell@cei.org]
Sent: Thursday, September 28, 2017 12:18 PM
To: Bolen, Brittany <bolen.brittany@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Scheduling a meeting with a visitor

Dear Brittany and Mandy, My friend of fifteen years, Owen Paterson, MP, is going to be in town next week, and I wonder if you or any of your colleagues would like to meet with him. Owen was cabinet minister for the Department of Environment, Food, and Rural Affairs in the Cameron government from 2012 to 2014. He was sacked because he was far too conservative and un-green for the Prime Minister. He is keen to re-establish contacts with key people in Washington on environmental and energy issues. I have pasted a short bio below. Owen is free for much of next Wednesday afternoon and evening the 4th and Thursday morning the 5th. He's giving a talk at lunch at CEI on Wednesday (which you are of course invited to attend), which will end at 1:30, and he's giving a speech at Heritage at noon on Thursday. Right now, the only definite appointment he has is 3 PM Wednesday with Lamar Smith. Thanks, Myron.

Right Honorable Owen Paterson, MP

Owen comes from an old farming family in Shropshire and has represented his home constituency of North Shropshire in the House of Commons since 1997. He served in the Conservative shadow cabinet as shadow minister for agriculture, fisheries, and food and then as shadow minister for Northern Ireland. When the Cameron Coalition government took office in 2010, he first served as secretary of state for Northern Ireland and from 2012 to 2014 as secretary of state for environment, food, and rural affairs. Owen then founded the think tank UK2020 and in 2015 was one of the three founders of Vote Leave, where he played a leading role in the successful Brexit campaign. Owen is a Cambridge graduate in history and worked for twenty years in the British leather industry, which included a term as president of the European tanning association.

Myron Ebell
Director, Center for Energy and Environment
Competitive Enterprise Institute
1310 L Street, N. W., Seventh Floor
Washington, DC 20005, USA
Tel direct: (202) 331-2256
Tel mobile: (202) 320-6685
E-mail: Myron.Ebell@cei.org
Stop continental drift!

Message

From: Braniff, Mimi P [mimi.braniff@delta.com]
Sent: 10/20/2017 1:05:50 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Baptist, Erik [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=10fc1b085ee14c6cb61db378356a1eb9-Baptist, Er]
Subject: RFS help for merchant refiners?

Mandy and Erik- The merchant refiners all woke up today to the news of the Administrator's letter to the corn belt Senators. Needless to say this has invoked a panic among the group. Is there anything on the table to help merchant refiners?
Happy to jump on a call to discuss as well. My direct line is below. Thanks. Mimi

Mimi Braniff | DELTA | Managing Director–Government Affairs
P: 202.243.3580 | 1212 New York Ave NW Ste 200 Washington, DC 20005

Message

From: Fu, Joshua S [jsfu@utk.edu]
Sent: 10/2/2017 9:03:00 PM
To: Webb, C. Flint [C.FLINT.WEBB@leidos.com]; Stephanie Glyptis [SGlyptis@AWMA.ORG]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; wwehrum@hunton.com; Cindy Fontanesi [CFontanesi@AWMA.ORG]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; jcmuffat Personal Email / Ex. 6
CC: Tracy Fedkoe [TFedkoe@AWMA.ORG]; cnelson [cnelson@mmm.com]; michele.gehring@coterie-env.com
Subject: Re: (UPDATE) RE: Climate Change Keynote Mandy

It is a big release.

Joshua

On 10/2/17, 2:09 PM, "Webb, C. Flint" <C.FLINT.WEBB@leidos.com> wrote:

>Thank you for taking care of this!
>
>
>Flint Webb, P.E.
>C.Flint.Webb@Leidos.com
>Baltimore-Washington Chapter: Vice Chair
>Technical Council: Climate Change Division Vice Chair
>Finding Common Ground on Climate Change Mitigation and Adaptation:
> General Conference Chair
>South Atlantic States Section: Director
>Air & Waste Management Association
>Work: 571-526-7706
>Cell: Personal Phone / Ex. 6
>
>
>-----Original Message-----
>From: Stephanie Glyptis [mailto:SGlyptis@AWMA.ORG]
>Sent: Monday, October 02, 2017 2:04 PM
>To: dominguez.alexander@epa.gov; wwehrum@hunton.com; Cindy Fontanesi;
>Gunasekara.Mandy@epa.gov; jcmuffat; Webb, C. F. [US-US]
>Cc: Tracy Fedkoe; cnelson; michele.gehring@coterie-env.com
>Subject: EXTERNAL: (UPDATE) RE: Climate Change Keynote Mandy
>Importance: High
>
>Flint et al ~
>
>I just spoke with Alexander Dominguez from Mandy's office. They have
>worked within their offices, and Samantha Dravis, Associate Administrator
>of EPA's Office of Policy, will be stepping in to speak as the Keynote.
>
>Ms. Dravis' Chief of Staff will be in touch with Cindy and me (Alex will
>be connecting us) and we'll work to get all the information updated on
>our end (i.e., website, promotions, final program).
>
>Alex,
>My sincerest thanks to you and Ms. Gunasekara's office for working so
>diligently with us on our Keynote speaker even with Mandy's schedule
>change. On behalf of the Association we truly appreciate EPA's support
>and participation.
>
>All the best,
>Stephanie
>
>Stephanie M. Glyptis
>Executive Director
>Air & Waste Management Association
>420 Fort Duquesne Boulevard
>One Gateway Center, Third Floor
>Pittsburgh, Pennsylvania 15222 USA
>Phone: 412.232.3444 (x6006)
>Direct: 412.904.6006

>Fax: 412.232.3450
>sglyptis@awma.org
>www.awma.org
>
>-----Original Message-----
>From: Webb, C. Flint [mailto:C.FLINT.WEBB@leidos.com]
>Sent: Monday, October 02, 2017 12:08 PM
>To: Dominguez, Alexander <dominguez.alexander@epa.gov>
>Cc: William L. Wehrum <wwehrum@hunton.com>; Cindy Fontanesi
><CFontanesi@AWMA.ORG>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>;
>jcmuffat Personal Email / Ex. 6
>Subject: RE: EXTERNAL: A&WMA's Conference "Finding Common Ground on
>Climate Change Mitigation and Adaption" Scheduled for October 10th and
>11th in Arlington VA
>
>Alex, What can we do to resolve the scheduling issue? Do we need to find
>a last minute replacement? It is probably too late to reflect the change
>in the Final Program.
>
>
>Flint Webb, P.E.
>C.Flint.Webb@Leidos.com
>Baltimore-Washington Chapter: Vice Chair Technical Council: Climate
>Change Division Vice Chair Finding Common Ground on Climate Change
>Mitigation and Adaptation:
> General Conference Chair
>South Atlantic States Section: Director
>Air & Waste Management Association
>Work: 571-526-7706
>Cell: Personal Phone / Ex. 6
>
>
>-----Original Message-----
>From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
>Sent: Monday, October 02, 2017 11:59 AM
>To: Webb, C. F. [US-US]; Dominguez, Alexander
>Cc: William L. Wehrum; cfontanesi@awma.org
>Subject: Re: EXTERNAL: A&WMA's Conference "Finding Common Ground on
>Climate Change Mitigation and Adaption" Scheduled for October 10th and
>11th in Arlington VA
>
>I have a scheduling issue on the 10th that needs to be worked out. I
>apologize. Please work with Alex (CC'd).
>
>Sent from my iPhone
>
>> On Oct 2, 2017, at 11:49 AM, Webb, C. Flint <C.FLINT.WEBB@leidos.com>
>>wrote:
>>
>> Thank you for stepping up to keynote our conference at the at the
>>DoubleTree hotel at 300 Army Navy Drive, Arlington, VA, October 10th.
>>As General Conference Chair, I will have the honor of introducing you
>>and I wanted to go over a few things ahead of time.
>>
>> Bio: Please provide me with a brief bio for me to use to introduce you.
>> How do you want us to show your name in the program?
>> 1) Amanda (Mandy) Gunasekara, Senior Policy Advisor to the
>>Administrator for the Office of Air and Radiation, U.S. EPA
>> 2) Amanda Gunasekara, ...
>> 3) Mandy Gunasekara, ...
>>
>> Speaker's Breakfast: There will be a speaker's Breakfast. There is a
>>Presenter's Breakfast 7:30-8:30 am. There will be tables set up for
>>each conference session. I will be at the Climate Communication Panel
>>Session table. I would recommend that you come to the Breakfast so you
>>can find out about any last-minute changes. You can also check the web
>>site https://www.awma.org/content.asp?admin=Y&contentid=311 for the
>>final program.
>>
>> Presentation: Pleas provide me with your PowerPoint presentation and I
>>will load it onto the computer for presentation.
>>
>> Schedule: After the Presenter's Breakfast at 8:30-8:40 am I am
>>scheduled to make a few welcoming remarks after which I will introduce
>>you. Please try to keep your presentation to 20-30 minutes so there is
>>adequate time for questions and answers. I will give you 5, 3 and 2
>>minute warning using hand signals. After your presentation I will thank
>>you and introduce Clara Poffenberger who will then introduce the Climate

>>Policy Update Panel. Our understanding is that you will not be able to
>>join us on the panel, but if that is correct let me know and we can
>>include you on the panel. The panel is scheduled to run from 9:10-10:10
>>am.
>>
>> If you have ANY questions please don't hesitate to contact me or Cindy
>>Fontanesi (copied on this e-mail). Cindy is our conference planner.
>>
>> See you on the 10th!
>>
>> Flint Webb, P.E.
>> C.Flint.Webb@Leidos.com
>> Baltimore-Washington Chapter: Vice Chair Technical Council: Climate
>> Change Division Vice Chair Finding Common Ground on Climate Change
>> Mitigation and Adaptation:
>> General Conference Chair
>> South Atlantic States Section: Director Air & Waste Management
>> Association
>> Work: 571-526-7706
>> Cell: Personal Phone / Ex. 6
>> -----Original Message-----
>> From: Jeffry Muffat Personal Email / Ex. 6
>> Sent: Thursday, September 14, 2017 8:08 AM
>> To: gunasekara.mandy@epa.gov
>> Cc: William L. Wehrum; cfontanesi@awma.org
>> Subject: EXTERNAL: A&WMA's Conference "Finding Common Ground on
>> Climate Change Mitigation and Adaption" Scheduled for October 10th and
>> 11th in Arlington VA
>>
>> Mandy:
>>
>> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate
>>Change. The Conference is scheduled for Oct 10-11, 2017 in Arlington,
>>VA and promises to be a great opportunity to exchange meaningful
>>information on the current thinking relative to climate change and how
>>we can mitigate any adverse effects and adapt to the potential
>>consequences. The Association values EPA's thinking and is excited to
>>provide the forum for discussion to our membership and other parties
>>involved in the discussion.
>>
>> Bill Wehrum said that you planned to check with Administrator Pruitt
>>one last time to see if he was available to Keynote and it would be
>>great if he wanted to speak. However, our intent at this time is to
>>list you in the Program at the Keynoter and then to send out a special
>>mailing/notice announcing Administrator Pruitt as the Keynoter should he
>>decide to speak.
>>
>> Cindy Fontanesi from A&WMA Headquarters in Pittsburgh will be in touch
>>with you today to work out the details.
>>
>> Again, thank you so much for agreeing to speak at our upcoming
>>Conference.
>>
>> Jeff Muffat
>> Retired Manager of 3M Environmental Reg Affairs Treasurer of Air &
>>Waste Management Association .

Message

From: Olsen, Elizabeth (EPW) [Elizabeth_Olsen@epw.senate.gov]
Sent: 10/10/2017 5:01:19 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Palich, Christian [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=330ad62e158d43af93fcbbece930d21a-Palich, Chr]
Subject: RE: Hello Stranger

Great seeing you too!

Ok, Awesome. Christian and I have already become quite the pen pals due to the nominations and qfr's. So we can transition to this letter, once the QFR's are done. Thanks Mandy!

Sincerely,
Elizabeth "Lizzy" Olsen, J.D.
Majority Director of Operations
Senate Committee on Environment and Public Works
C: (202) 407-3841
O: (202)224-6176

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Friday, October 6, 2017 5:56 PM
To: Olsen, Elizabeth (EPW) <Elizabeth_Olsen@epw.senate.gov>
Cc: Palich, Christian <palich.christian@epa.gov>
Subject: RE: Hello Stranger

Lizzy,
Great seeing you the other day. I'm looping in Christian to help provide a response to your below requests.
Hope you have a great weekend!
Mandy

From: Olsen, Elizabeth (EPW) [mailto:Elizabeth_Olsen@epw.senate.gov]
Sent: Tuesday, September 26, 2017 11:37 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Hello Stranger

Hi Mandy!

I miss you around here! I hope all is well with the adorable family!

I have a question to ask you.... I am drafting up a letter to yall right now and I was curious if there was anything that the past EPA was mishandling or hiding that you think the new EPA is really taking steps to change, has changed or intends to change or any materials specifically that you think expose past practices, policies or responses that you are changing in the new EPA? I know it is a lofty question but it is basically because I am opening to all answers.

I have basically gone through all of our correspondence with EPA and tried to come up with a short list but you have experience on both sides so I figured I would ask you. It would also make this more of a cooperative letter. Anywho, let me know if you can think of anything! Send my love to the old team.

Very best,

Elizabeth "Lizzy" Olsen, J.D.
Majority Director of Operations
Senate Committee on Environment and Public Works
C: (202) 407-3841
O: (202)224-6176

Message

From: Consolvo, Brandon [Brandon.Consolvo@mail.house.gov]
Sent: 10/10/2017 12:17:39 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Lyons, Troy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=15e4881c95044ab49c6c35a0f5eef67e-Lyons, Troy]
Subject: RE: Clean power

Very helpful, thanks!

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Tuesday, October 10, 2017 8:16 AM
To: Consolvo, Brandon <Brandon.Consolvo@mail.house.gov>
Cc: Lyons, Troy <lyons.troy@epa.gov>
Subject: Re: Clean power

Hey Brandon, couple of notes below.
- Yes, this is a part of the rule making process.
- This is the first step - a proposed repeal rule - which will be open for comment for 60 days. The next step will be a final rule.

-- We've been working on this since my first day (late March). The regulatory process requires extensive legal and technical analysis as well as an interagency review organized through OMB. As an example, the proposed repeal rule interagency review process lasted over 90 days and that's just one step.

- The proposed repeal is premised on CPP exceeding its statutory authority by requiring states to take actions that extend beyond the fenceline.

Sent from my iPhone

On Oct 10, 2017, at 7:42 AM, Consolvo, Brandon <Brandon.Consolvo@mail.house.gov> wrote:

> Just need a few bullets on the timing question (perhaps just a little color on the notice, comment, etc part of your email). Is this part of the rule making process?
>
> To be clear, this is not in an accusatory manner, but we are wondering when didn't this happen sooner? Seems like low hanging fruit.
>
> ---
>
> **From:** Lyons, Troy [mailto:lyons.troy@epa.gov]
> **Sent:** Tuesday, October 10, 2017 7:38 AM
> **To:** Consolvo, Brandon <Brandon.Consolvo@mail.house.gov>
> **Cc:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Re: Clean power
>
> I have added Mandy who can explain the timing, but the layman explanation is that several actions had to occur (notice, comment, etc) before the proposed withdraw could be issued.

Let us know what you need on this.

Troy M. Lyons
Associate Administrator
Office of Congressional & Intergovernmental Relations
U.S. Environmental Protection Agency
202-309-2490 (cell)

Sent from my iPhone

On Oct 10, 2017, at 5:31 AM, Consolvo, Brandon <Brandon.Consolvo@mail.house.gov> wrote:

> Hey, serious question, can you explain the timing of the clean power plant rule? Why wasn't this rolled back sooner?
>
> Brandon Consolvo
> Majority Leader Kevin McCarthy

Message

From: Jay Cranford [cranford@cgcn.com]
Sent: 10/4/2017 9:05:51 PM
CC: Michael Freeman [freeman@cgcn.com]
Subject: Coalition for Regulatory Innovation

Good afternoon,

We wanted to pass along the press release below announcing the launch of the Coalition for Regulatory Innovation. Please feel free to forward this along to any of your contacts, and let us know if you have any questions. – Jay

JAY CRANFORD | CGCN GROUP
1101 K STREET, NW, SUITE 650 WASHINGTON, D.C. 20005
202.689.9296 / cranford@cgcn.com / www.cgcn.com

Coalition for Regulatory Innovation Launches Effort to Modernize our Regulatory System

For more information about the Coalition for Regulatory Innovation, view this op-ed penned by National Association of Manufacturers President Jay Timmons and North America's Building Trades Unions President Sean McGarvey.

Regulations dictate just about every aspect of our daily lives, from where we live to

what we eat and how we work. Some rules make sense. Others don't. And new rules are multiplying faster than ever.

This week, we are excited to announce the launch of the Coalition for Regulatory Innovation. Our aim is to help Americans understand the thicket of state and federal rules and champion commonsense reforms that remove unnecessary burdens on the economy. The Coalition will highlight some of the most misguided rules and outline principles for reform.

Our country's ever-growing tangle of state and federal rules are constricting job growth and stifling business investments throughout the broader economy. Regulations have proliferated so swiftly that it would be impossible to unravel this knot one rule at a time.

Our existing regulatory regime was designed for an earlier era, not the rapid change of today's economy, much less the next era 10 or 20 years from now. The current patchwork of rules is ill-equipped to govern emerging technologies or the changing face of American commerce. We need to fundamentally redesign the system by modernizing the rules that don't work and establishing a better process to enact new ones.

Congress needs to establish basic parameters to modernize federal rule-making. In our view, there are three pillars of effective, bipartisan regulatory reform: transparency, scientific integrity and accountability. Rulemaking should be conducted out in the open and backed up by objective, unimpeachable science, while being overseen by officials who are held accountable to the voters.

Enacting real reforms will unshackle the economy and generate faster job creation. The most dynamic, innovative economy in the world shouldn't have the most outdated regulatory system. Our Coalition will offer policymakers and voters a roadmap to modernize the economy. Americans deserve better. We want to help them adopt those improvements.

Download the Op-Ed here

Share Tweet Forward Share

The Coalition for Regulatory Innovation is a bipartisan coalition made up of diverse members that represent a wide range of sectors within the U.S. economy. The coalition shares the common mission of examining the impact of regulations on our small businesses, communities and overall economy to create a smart path forward for a transparent, efficient and accountable regulatory system.

Twitter Website Email

This email was sent to Elena.Connolly@fticonsulting.com

why did I get this? unsubscribe from this list update subscription preferences

Coalition for Regulatory Innovation · info@coalitionforregulatoryinnovation.com · Washington, D.C. 20004 · USA

Confidentiality Notice:

This email and any attachments may be confidential and protected by legal privilege. If you are not the intended recipient, be aware that any disclosure, copying, distribution or use of the e-mail or any attachment is prohibited. If you have received this email in error, please notify us immediately by replying to the sender and then delete this copy and the reply from your system. Thank you for your cooperation.

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/13/2017 2:37:07 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Draft RH SIP and supporting docs part 3
Attachments: 12_D1_2013_WhiteBluff_BART.pdf; 13_D2_Letter to Entergy 4_5_2017.pdf; 14_D3_Entergy Response 4-21-2017.pdf; 15_D4_8_18_17 _White Bluff_redact.pdf; 16_D5_8_2015_EAI_Comments_on_Propose.pdf; 17_D6_8_2016_Supplemental_Comments_of_Ent.pdf

Part 3.

Stuart Spencer
Associate Director- Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
Ph. # (501) 682-0750
Fax # (501) 682-0880
E-mail: SPENCER@adeq.state.ar.us
Web: http://www.adeq.state.ar.us

This e-mail and any files transmitted with it are the property of the Arkansas Department of Environmental Quality, and are intended solely for the use of the individual or entity to whom this email is addressed. If you are not the named recipient(s) or otherwise have reason to believe that you have received this message in error, please notify the sender at (501) 682-0750 and delete this message immediately from your computer. Any other use, retention, dissemination, forwarding, printing or copying of this email is strictly prohibited.

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-12-078

October 14, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – White Bluff Plant
Revised BART Five-Factor Analysis
Permit No. 0263-AOP-R7, AFIN 35-00110

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for the Entergy Arkansas, Inc – White Bluff Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the revised FFA which was submitted on June 10, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

Entergy Response to 8/21/2013 EPA Region 6 comments on the White Bluff BART FFA

Entergy has reviewed the comments provided by EPA Region 6 on August 21, 2013, and appreciates the opportunity to provide the below response. To simplify the format of this response, we have included each of EPA's comments, followed by our response. Submitted concurrently herewith is a revised Five-Factor Analysis (FFA) incorporating several revisions as discussed below.

NOx BART

- **EPA Comment 1** - The 2012 S&L NOx Study identifies neural net system upgrades as a potential NOx control. However, this control option is not evaluated by Entergy in the BART analysis for Units 1 and 2. While it appears that the added visibility benefit of LNB/SOFA + SNCR compared to LNB/SOFA is too small to justify the added cost of installing SNCR, we believe the added cost of LNB/SOFA + Neural Net System Upgrades compared to LNB/SOFA would likely be small and may provide some visibility benefit. ADEQ should ensure that if a NOx emission limit more stringent than 0.15 lb/MMBtu could be expected from LNB/SOFA + Neural Net System Upgrades, this should be evaluated as a separate control option in the BART analysis.

  Entergy Response – Entergy does not believe that operation of neural network system upgrades in conjunction with LNB/SOFA would result in a NOx emission limit more stringent than the 0.15 lb/MMBtu proposed in the FFA. The information[1] presented in the S&L NOx study regarding neural network system upgrades was an estimate of the level of NOx reductions which could potentially be achieved through implementation of neural network system upgrades for the White Bluff units as currently configured (without LNB/SOFA). As no vendor guarantees were available for the NOx performance of such neural network system upgrades, and the level of NOx emission reduction estimated by S&L from the operation of neural network system upgrades alone (10%) was significantly less than the potential NOx emission reductions achievable by other evaluated control technologies, no consideration was given to this option in the FFA.

  Since receiving this question from EPA, Entergy has conducted additional discussions with S&L regarding the potential for neural network system upgrades to be operated in conjunction with LNB/SOFA to achieve additional levels of NOx control beyond that expected from LNB/SOFA alone. S&L provided the following statement on this subject.

  > The Neural Network (NN) is a computer program that evaluates controllable parameters affecting the NOx emission rate from the boiler and learns over a long period of operation (years) how to minimize the NOx emission rate. The suppliers of NN do not

[1] Percent NOx emission reduction and expected NOx emission rates

offer a guarantee on NOx emission rate or percent reduction. The primary benefit is to maintain over time the guaranteed NOx emission rate performance resulting from LNB/SOFA. There are NN installations that have achieved small improvements in NOx emission rate over a long period of time but as previously stated, the NN suppliers aren't offering guarantees and the NN may take many years to realize the performance improvement. While this combination of technologies may be desirable in the long run, we don't recommend it as a separate NOx control option to be evaluated in the BART analysis.

Based on the lack of a NOx emission reduction guarantee, Entergy does not believe that the combination of NN system upgrades with LNB/SOFA should be evaluated as a separate, distinct control option within the FFA.

Cost Analysis for SO_2 and NO_x Controls

- **EPA Comment 2** - We are not providing an exhaustive line-by-line review of costs for SO2 and NOx controls because we do not anticipate that further revisions to the cost numbers would change the ultimate BART determinations. However, we wish to make clear that EPA disagrees that the Control Cost Manual (CCM) allows for AFUDC to be included in the BART cost evaluation. AFUDC is the cost of capital that is incurred to finance the project during the construction period. While AFUDC is a valid cost under the all-in cost estimating methodology, it is not a valid cost under the CCM methodology. The Regional Haze Rule states the CCM should be followed where possible, and the CCM uses overnight costing methodology. The overnight cost method is the cost of a construction project if no interest is incurred during construction, as if the project is completed overnight. Thus, AFUDC is never valid under the CCM overnight cost approach. ADEQ should ensure that the cost estimates for all SO2 and NOx controls are revised to exclude AFUDC in order to reflect an accurate estimate of cost-effectiveness of controls.

Entergy Response – Entergy continues to believe that the overnight costing methodology advocated by EPA represents an overly simplistic view of the true costs associated with a significant pollution control project such as those evaluated by Entergy in this FFA. AFUDC represents the interest expense on the investment in the technology that is incurred during construction, before the equipment is placed in service. For major control technology installations, such as scrubbers or SCR, the interest expense incurred during the 30 - 46 months of construction can reach $30 million to $60 million for a large unit. AFUDC simply includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs.

Entergy does not agree that the CCM requires the company to exclude AFUDC from control technology costs. Nonetheless, although Entergy is not waiving its ability to include AFUDC in

future control cost analyses, to expedite ADEQ's consideration of the FFA for White Bluff, we have revised the FFA document to remove AFUDC from the costs of each evaluated pollution control technology as requested by EPA staff. While this change lowers the overall capital costs presented within the latest FFA, the BART determinations for each affected pollutant (SO_2 and NO_X) remain unchanged.

Auxiliary Boiler (SN-05)

- **EPA Comment 3** - The calculations provided indicate that average sulfur content over the 2009-2011 period and the average heat content over this same period were utilized to estimate the modeled emission rate. The use of average values based on a three year average of annual values is inconsistent with estimating the maximum 24-hr emission rate from the baseline period. Please provide additional information on the variability of sulfur content and heat content in order to estimate the range of the maximum impact.

  Entergy Response – Entergy reviewed the monthly fuel oil sampling data for the facility along with daily records of aux. boiler hours of operation for 2009-2011. Over the 2009-2011 period, the heat content of the fuel oil ranged from 134,318 btu/gal to 142,422 btu/gal, and the sulfur content ranged from 0.004% to 0.056%[2]. By combining each month's fuel sampling result for heat and oil sulfur content with the maximum daily hours of operation for the aux. boiler for the month, it is possible to produce a refined estimate of the maximum daily (24-hour) average SO_2 emission rate from this unit.

  Based on this data, the maximum 24-hour average SO_2 emission rate occurred on May 10, 2009. The monthly fuel analysis for May 2009 indicates a heat content of 135,438 btu/gal (135.438 MMBtu/Mgal) and a sulfur content of 0.0441% by weight. Based on the emission factor presented in AP-42 Table 1.3-1 for distillate fuel-fired boilers of >100 MMBtu/hr (142S lb/Mgal), the SO_2 emission factor for May 2009 is calculated as 0.0462 lb/MMBtu. At the maximum 24-hour average heat input rate for May 2009 of 121.23 MMBtu/hr[3], the maximum 24-hour average SO_2 emission rate for the 2009-2011 period is calculated as 5.61 lb/hr.

  This refined estimate of the maximum baseline 24-hour SO_2 emission rate for the aux. boiler is less than the rate (5.8 lb/hr) which was utilized to estimate the baseline visibility impairment

[2] Entergy notes that the sulfur content of the No. 2 fuel oil used at White Bluff has trended downward over time, with the annual average sulfur content for 2011 being 0.013% and the average for 2012 being 0.0042%. Due to the increasing restrictions on the sulfur content of commercially available No. 2 fuel oil, it is unlikely that the sulfur content in future years will return to past levels.

[3] This rate was calculated based on the maximum daily hours of operation in May of 2009 (15.9 hours on May 10) and the maximum heat input capacity of the aux. boiler (183 MMBtu/hr). This calculation assumes that the aux. boiler was operating at the maximum rated capacity at all times that it was online on this date. This assumption results in an over-estimate of the actual average heat input for this date.

attributable to this unit. As such, the analysis presented within the FFA is conservative and no refinement to the modeled SO_2 emission rate for the aux. boiler is necessary.

- **EPA Comment 4** - The rationale for determining that no additional controls are required for this unit differs in the revised BART report and the response to Region 6 comments you provided (comment 16). Please revise the BART report to be consistent with your response to our comments, as the response provides an appropriate justification for no additional controls at the auxiliary boiler.

  Entergy Response – The BART FFA report has been revised to include the rationale for determining that no additional controls are required for the auxiliary boiler which was presented in the June 2013 response to comments document.

REVISED BART FIVE FACTOR ANALYSIS
WHITE BLUFF STEAM ELECTRIC STATION
REDFIELD, ARKANSAS (AFIN 35-00110)

Prepared By:

TRINITY CONSULTANTS, INC.
201 NW 63rd St., Suite 220
Oklahoma City, Oklahoma 73116
(405) 848-3724

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77203
(501) 377-4000

Trinity Project No. 123701.0053

October 2013

Entergy
THE POWER OF PEOPLE

Trinity Consultants

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INTRODUCTION AND BACKGROUND 2-1

3. MODELING METHODOLOGIES AND PROCEDURES 3-1
3.1 CALMET AND CALPUFF 3-1
3.2 CALPOST 3-1

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT 4-1
4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES 4-1
4.2 BASELINE VISIBILITY IMPAIRMENT 4-2

5. SO_2 BART EVALUATION 5-1
5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02 5-1
5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02 5-1
5.2.1 DRY SORBENT INJECTION 5-1
5.2.2 SEMI-DRY SCRUBBER 5-2
5.2.3 WET SCRUBBER 5-2
5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR SN-01 AND SN-02 5-3
5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02 5-3
5.4.1 COST OF COMPLIANCE 5-4
5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS 5-7
5.4.3 REMAINING USEFUL LIFE 5-7
5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02 5-7
5.6 PROPOSED BART FOR SO_2 FOR SN-01 AND SN-02 5-13
5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS 5-13
5.7 SO_2 BART FOR SN-05 5-14

6. NO_X BART EVALUATION 6-1
6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02 6-1
6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES 6-1
6.2.1 COMBUSTION CONTROLS 6-2
6.2.1.1 Flue Gas Recirculation (FGR) 6-2
6.2.1.2 Overfire Air (OFA) / Separated Overfire Air (SOFA) 6-2
6.2.1.3 Low NO_X Burners (LNB) 6-3
6.2.2 POST COMBUSTION CONTROLS 6-3

6.2.2.1 Selective Catalytic Reduction (SCR) 6-3
6.2.2.2 Selective Non-Catalytic Reduction (SNCR) 6-3
6.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS . 6-5
6.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS 6-5
6.4.1 COST OF COMPLIANCE 6-5
6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS 6-9
6.4.3 REMAINING USEFUL LIFE 6-9
6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS 6-10
6.6 PROPOSED BART FOR NO_X FOR SN-01 AND SN-02 6-16
6.7 PROPOSED BART FOR NO_X FOR SN-05 6-16

7. PM_{10} BART EVALUATION 7-1

APPENDIX A (SO_2 AND NO_X CONTROL COST CALCULATIONS)

APPENDIX B (BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT)

APPENDIX C (CALMET MODELING PROTOCOL)

APPENDIX D (CEMS DATA FROM CAMD FOR 2001 TO 2003 AND 2009 TO 2011)

APPENDIX E (S&L NO_X CONTROL TECHNOLOGY STUDY)

LIST OF TABLES

TABLE 1-1. MODELED EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01, SN-02 AND SN-05 1-2

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION 3-3

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS 3-3

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS 3-3

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS 3-3

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS) 4-2

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT 4-3

TABLE 4-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT 4-4

TABLE 4-4. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT 4-5

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02 5-1

TABLE 5-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES 5-3

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 SO_2 CONTROLS 5-6

TABLE 5-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS 5-8

TABLE 5-5 SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003) 5-9

TABLE 5-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-02 (2001-2003) 5-10

TABLE 5-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT 5-12

TABLE 5-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT 5-12

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02 6-1

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES 6-5

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 NO_X CONTROLS 6-8

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT NO_X CONTROLS 6-11

TABLE 6-5. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-01 (2001-2003) 6-12

TABLE 6-6. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-02 (2001-2003) 6-13

TABLE 6-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT 6-15

TABLE 6-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT 6-15

TABLE B-1. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT 7-9

TABLE B-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT 7-9

TABLE B-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT 7-10

1. EXECUTIVE SUMMARY

This report is a revision to "BART Five Factor Analysis" submitted to ADEQ on February 21, 2013, and revised and resubmitted on June 10, 2013. This report is submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.'s (Entergy's) BART-affected electric generating units (EGUs) at the White Bluff including changes made in response to EPA's comments and suggestions on the previous submittal, which were received by Entergy on March 6 and August 21, 2013. This analysis updates and replaces the previous June 2013 FFA. The BART determination for each pollutant has not changed.

Entergy operates three BART-affected EGUs at White Bluff: two coal-fired primary boilers (SN-01 and SN-02) and one fuel oil-fired auxiliary boiler (SN-05). The coal-fired boilers are identical tangentially-fired boilers with a maximum net power rating of 850 MW each and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr) each. The boilers burn sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel. SN-01 and SN-02 are currently equipped with electrostatic precipitators (ESPs).

The Auxiliary Boiler, SN-05, is a 183 MMBtu/hr auxiliary boiler burning No. 2 fuel oil or biodiesel as its only fuel types. The purpose of the Auxiliary Boiler is to provide steam for the start-up of the two primary boilers, SN-01 and SN-02. There is no emissions control equipment connected to the Auxiliary Boiler. Typically, the Auxiliary Boiler is only used in the rare instance when both of the main boilers are not operating.

Based on modeling performed for this analysis, cumulative emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from SN-01, SN-02, and SN-05 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) of visibility impairment in four (4) Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[2, 3]. A summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 based on default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of continuous emissions monitoring system (CEMS) data as reported to EPA's Clean Air Markets Database (CAMD), stack testing, and annual emissions inventory information as further described in Section 4 of this report.

---

[1] SN-01 and SN-02 primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the 2001-2003 and 2009-2011 baseline periods evaluated in this analysis.

[2] SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. *See* Table 4-4.

[3] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ's) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

TABLE 1-1. MODELED EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01, SN-02 AND SN-05

Source	CACR		UPBU		HERC		MING	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
SN-05	0.010	0	0.005	0	0.004	0	0.008	0
SN-01	1.628	106	1.140	77	1.041	61	0.887	56
SN-02	1.695	112	1.185	80	1.060	65	0.903	57

Trinity used the EPA's BART guidelines in 40 CFR Part 51[4] and other recent EPA guidance[5] to determine BART for the boilers. Trinity conducted a five-step analysis to determine BART for SO_2 and NO_x that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The BART analysis concluded that the installation of a semi-dry FGD system constitutes BART for SO_2 for both SN-01 and SN-02. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu on a rolling 30-day average. Since baseline visibility modeling showed that there is no opportunity for visibility improvement attributable to SN-05, because not a single day greater than 0.5 Δdv is associated with SN-05, it is not possible to install control equipment to improve visibility. Therefore, *no controls* is the SO_2 BART determination for SN-05.

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.15 lb/MMBtu through the installation and use of low NO_X burners and separated overfire air (LNB/SOFA) represents BART for SN-01 and SN-02.[6] Based on the same logic outlined above for SO_2, NO_x controls are not appropriate or required for SN-05.

---

[4] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

[6] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012)), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NOx regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NOx obligations under BART as EPA has previously determined that the CAIR season NOx trading program provides greater visibility improvement than BART.

EPA approved a BART determination for PM_{10} at SN-01 and SN-02 in its March 12, 2012, final rule based on the existing ESPs, and established a BART emission rate of 0.1 lb/MMBtu for each boiler.[7]

[7] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[8] The BART rule defines BART-eligible sources as sources that meet the following criteria:

1. Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant;
2. Began operation between August 7, 1962 and August 7, 1977; and
3. Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[9] Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *...an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by...[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

---

[8] The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308.

[9] The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA's 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

A BART determination should be made for each visibility-affecting pollutant (VAP) by following the five steps listed above for each VAP.

SN-01 and SN-02 meet the three BART-eligibility criteria described above, and the existing visibility impairment attributable to each boiler is greater than 0.5 Δdv in at least one Class I area. Thus, SN-01 and SN-02 are subject to BART. SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area[10] but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. Details of the existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by the boilers include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_X, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

[10] *See* Table 4-4.

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG).[11]

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI(\text{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to

[11] The 2010 FLAG guidance, which was issued in draft form on July 8, 2008, and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta dv = 10 * \ln\left[\frac{b_{ext,\ background} + b_{ext,\ source}}{b_{ext,\ background}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[NH_4(SO_4)_2]_{Small} + 4.8 f_L(RH)[NH_4(SO_4)_2]_{Large} + \\ 2.4 f_S(RH)[NH_4NO_3]_{Small} + 5.1 f_L(RH)[NH_4NO_3]_{Large} + \\ 2.8[OC]_{Small} + 6.1[OC]_{Large} + 10[EC] + 1[PMF] + 0.6[PMC] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[NO_2] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ (µg/m^3)	NH_4NO_3 (µg/m^3)	OM (µg/m^3)	EC (µg/m^3)	Soil (µg/m^3)	CM (µg/m^3)	Sea Salt (µg/m^3)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on CAMD data from 2001-2003 for SO_2 and from 2009-2011 for NO_X[12]. The 2001-2003 period was not used for NO_X because that period no longer represents actual operation of the boilers. In 2006, Entergy completed the addition of a neural net system and also conducted extensive boiler tuning. These projects substantially reduced NO_X emissions. Accordingly, there is a real difference in operations/emissions between the original baseline period (2001-2003) and current operations such that the 2001-2003 time period is not representative of current (and thus future, post-BART) operations. The BART regulation, at 40 CFR Part 51, Appendix Y, Section IV.D.4.c, speaks to this issue:

> *The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.*

Using the emission rates from 2001-2003 for NO_X would over-state the emissions reductions from the proposed BART control technology. Moreover, using the 2001-2003 NO_X emission rates would exaggerate the projected visibility improvement in the Class I areas. Thus, updating the NO_X emission rates to represent current, normal operation better comports with the regulations. Entergy submitted a determination request to ADEQ on August 23, 2012, to use the 2009-2011 NO_X emission rates based on CEMS data. ADEQ and EPA determined that using the 2009-2011 NO_X emission rates is consistent with the BART guidance[13].

The PM_{10} emission rates are based on emission factors from AP-42 for PM_{10} filterable and PM condensable with a 99.5% control efficiency for ESP applied to the PM_{10} filterable in conjunction with the average coal heat value and average coal % ash from 2009-2011. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS)

---

[12] *See* Appendix D.

[13] *See* Email, dated September 10, 2012, from Guy Donaldson (EPA, Region VI) to Mary Pettyjohn (ADEQ).

"speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP.*[14] More specifically, the NPS workbook shows the following baseline distribution for the PM species:

- Coarse PM (PM_C) = 33.6%
- Fine soil (modeled as PM_F) = 25.9%
- Fine elemental carbon (modeled as EC) = 1.0 %
- Organic condensable PM (modeled as SOA) = 7.9%
- Inorganic condensable PM (modeled as SO_4) = 31.6%

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Source	SO_2[15] (lb/hr)	NO_X[16] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-05	5.8	31.7	2.8	0.9	0.5	1.2	0.2	0.1
SN-01	7,763.5	3,001.4	118.6	36.8	40.4	31.1	9.2	1.2
SN-02	7,825.1	3,527.4	118.6	36.8	40.4	31.1	9.2	1.2

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to SN-01, SN-02, and SN-05 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[17] Table 4-2, Table 4-3, and Table 4-4 provide a summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 respectively, based on the emission rates shown in Table 4-1. These tables show the maximum impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

---

[14] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 118.6 lb/hr, heat value of 8,950 Btu/lb, sulfur content of 0.27% and, ash content of 4.87%.

[15] The SO_2 hourly rates were derived from EPA's CAMD data for 2001 - 2003. The 2001-2003 max daily rates were 183,324 lb/day and 187,802 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[16] The NO_X hourly rates were derived from EPA's CAMD data for 2009-2011. The 2001-2003 max daily rates were 72,034 lb/day and 84,658 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[17] Due to an EPA-requested change in meteorological data which excluded Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. *See* footnote 1, above.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	1.287	0.336	0.003	0.002
2002	2.111	1.386	30	0.662	0.659	0.011	0.054
2003	4.194	1.130	35	0.722	0.385	0.003	0.020
Upper Buffalo Wilderness							
2001	2.339	1.128	34	0.835	0.290	0.003	0.000
2002	1.544	0.818	18	0.680	0.133	0.003	0.002
2003	1.900	1.140	25	1.117	0.021	0.003	0.000
Hercules Glades Wilderness							
2001	1.737	1.041	28	0.961	0.078	0.002	0.000
2002	1.288	0.617	13	0.487	0.128	0.001	0.000
2003	2.230	0.786	20	0.699	0.085	0.002	0.000
Mingo Wilderness							
2001	1.569	0.887	18	0.828	0.053	0.003	0.002
2002	1.012	0.750	24	0.427	0.319	0.002	0.002
2003	1.114	0.702	14	0.448	0.245	0.003	0.007

Table 4-2 demonstrates that the 98th percentile impacts from SO_4 are always greater than the 98th percentile impacts from NO_3. Therefore, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-01.

TABLE 4-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	1.292	0.398	0.003	0.002
2002	2.270	1.481	33	0.964	0.465	0.011	0.041
2003	4.437	1.169	38	0.595	0.555	0.004	0.015
Upper Buffalo Wilderness							
2001	2.385	1.185	35	0.840	0.343	0.003	0.000
2002	1.618	0.846	20	0.685	0.156	0.003	0.003
2003	1.998	1.176	25	0.958	0.215	0.003	0.000
Hercules Glades Wilderness							
2001	1.838	1.060	30	0.966	0.092	0.002	0.000
2002	1.340	0.643	14	0.490	0.151	0.001	0.001
2003	2.263	0.806	21	0.703	0.101	0.002	0.000
Mingo Wilderness							
2001	1.701	0.903	18	0.834	0.063	0.003	0.003
2002	1.031	0.805	25	0.674	0.129	0.002	0.000
2003	1.150	0.750	14	0.452	0.288	0.003	0.008

Table 4-3 demonstrates that the 98th percentile impacts from SO_4 are always greater than the 98th percentile impacts from NO_3. Therefore, as with SN-01, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-02.

TABLE 4-4. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	0.001	0.007	0.000	0.000
2002	0.02	0.005	0	0.001	0.004	0.000	0.000
2003	0.036	0.01	0	0.002	0.008	0.000	0.000
Upper Buffalo Wilderness							
2001	0.014	0.004	0	0.001	0.003	0.000	0.000
2002	0.009	0.004	0	0.003	0.000	0.000	0.000
2003	0.013	0.005	0	0.001	0.004	0.000	0.000
Hercules Glades Wilderness							
2001	0.007	0.004	0	0.001	0.003	0.000	0.000
2002	0.006	0.003	0	0.001	0.002	0.000	0.000
2003	0.008	0.004	0	0.002	0.001	0.000	0.000
Mingo Wilderness							
2001	0.009	0.003	0	0.000	0.003	0.000	0.000
2002	0.019	0.008	0	0.001	0.007	0.000	0.000
2003	0.015	0.003	0	0.001	0.002	0.000	0.000

Table 4-4 demonstrates that the 98th percentile impacts from the combined pollutants are well below the 0.5 Δdv threshold to be considered a contributor to visibility impairment.

5. SO_2 BART EVALUATION

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from SN-01 and SN-02, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 will reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for SN-01 and SN-02 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as SN-01 and SN-02 currently use a low sulfur fuel and thus would not achieve significant additional reductions through alternative fuel supplies comparable to the most efficient add-on controls. The available SO_2 control technologies are Dry Sorbent Injection (DSI), semi-dry scrubbing, and wet scrubbing.

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

SO_2 Control Technologies
Dry Sorbent Injection
Semi-Dry Scrubbing
Wet Scrubbing

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a sorbent into the exhaust gas stream where SO_2 reacts with and becomes entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time, gas stream temperature, and limitations of the particulate

control device, sorbent injection control efficiency can range between 40 and 60 percent.[18] This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.2 SEMI-DRY SCRUBBER

There are various designs of semi-dry scrubbing; or fuel gas desulfurization (FGD); systems, including the Spray Dryer Absorber (SDA) and Circulating Dry Scrubber (CDS) designs. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

In the CDS process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

Semi-dry scrubbing control efficiencies range from 60 to 95 percent,[19] and is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an electrostatic precipitator (ESP) to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similar to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Wet lime scrubbing is generally capable of achieving 80-95 percent control.[20] Higher control efficiencies may be achieved in certain applications. This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

---

[18] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[19] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

[20] *Id.*

EPA has recently suggested the control from wet scrubbing can achieve emissions reductions of up to 97%. Engineering evaluations conducted on Unit 1 and 2 by Sargent & Lundy (S&L) suggest that a control efficiency of up to 97% may be achievable through the application of wet scrubbing for higher-sulfur coals. However, as no vendor guarantee for greater than 95% control from wet scrubbing was available, Entergy cannot confidently rely on this level of control specific to SN-01 and SN-02. Moreover, Entergy has not received any assurances from vendors or its engineering consultant, S&L, of achieving such a level on a consistent, 30-day average basis.

5.3 Rank of Technically Feasible SO_2 Control Options by Effectiveness for SN-01 and SN-02

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the VAP. Table 5-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 5-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Estimated Control Efficiency
Wet Scrubber	80-95%[21]
Semi-Dry Scrubber	60-95%
Dry Sorbent Injection	40-60%

5.4 Evaluation of Impacts for Feasible SO_2 Controls for SN-01 and SN-02

The fourth step in the BART analysis is the impact analysis where the impacts for those control options deemed feasible in Step 2 are evaluated. This analysis is typically conducted to demonstrate that a control technology that is more effective than another technology does not constitute BART. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

Wet and dry scrubbing are the most effective technologies at reducing SO_2. As shown in Table 5-2, both technologies can achieve 95 percent reduction in SO_2.

[21] Estimated efficiency for wet FGD for low-sulfur coals typically combusted at White Bluff. Higher efficiencies are achievable for wet FGD when burning higher-sulfur coal, but may not be achievable for the low-sulfur coal typically combusted at SN-01 and SN-02.

Site-specific specifications from S&L indicate that semi-dry scrubbing can achieve an outlet rate of 0.06 lb/MMBtu on a 30-day rolling average basis. Entergy believes that semi-dry scrubbing represents a superior technology in comparison to wet scrubbing, thus the majority of research for this analysis has been focused on this control option. Information from S&L also indicate that wet scrubbing may be able to achieve an outlet rate of 0.04 lb/MMBtu on a 30-day rolling average basis.[22] These emission levels represent reductions of 95% for semi-dry scrubbing and 97% for wet scrubbing when applied to the facility's current maximum allowable SO_2 emission rate of 1.2 lb/MMBtu. Notwithstanding a lack of vendor assurances, for the purposes of this analysis, wet scrubbing has been evaluated at an outlet SO_2 emission rate of 0.04 lb/MMBtu.

5.4.1 COST OF COMPLIANCE

Control Costs

The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the cost effectiveness calculations are provided in Appendix A of this report.

The capital and direct operating and maintenance (O&M) costs of a semi-dry scrubber used in the cost effectiveness calculations were based on vendor estimates. The indirect operating costs such as property tax and insurance are based on calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual for wet acid gas absorber systems. The capital and O&M costs of a wet scrubber used in the cost effectiveness calculations are based on vendor estimates for a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) and calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual. The costs for a system capable of achieving equivalent control with an inlet SO2 rate of 1.2 lb/MMBtu or 0.04 lb/MMBtuwould be approximately 5 to 6 percent higher. The capital cost associated with a wet scrubber system is considerably higher than for a semi-dry scrubber system.

It should be noted that the capital costs presented for the SO_2 control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a scrubber installation, which can take several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate timely review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

[22] The cost estimate from S&L for a wet FGD system represents a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) S&L has indicated the cost for a system capable of achieving 97% control for an inlet SO_2 rate of 1.2 lb/MMBtu (0.04 lb/MMBtu) would be 5 to 6 percent higher. Entergy has not received any guarantee that an outlet SO_2 emission rate of 0.04 lb/MMBtu is consistently achievable for SN-01 or SN-02.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was the average rate from 2001-2003, as reported by Entergy in their air emission inventories. The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable for the control technologies multiplied by the future annual heat input. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001-2003 for each boiler.

Cost Effectiveness

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 5-3 indicates that the cost effectiveness of semi-dry scrubber at an SO_2 rate of 0.06 lb/MMBtu is approximately $2,913 per ton of SO_2 removed for SN-01 and $3,355 per ton of SO_2 removed for SN-02. The incremental costs for wet scrubbing at 0.04 lb/MMBtu over semi-dry scrubbing at 0.06 lb/MMBtu are $26,701/ton for SN-01 and $27,218/ton for SN-02. As documented in Section 5.5 below, the additional cost of wet FGD is not justified in light of the negligible improvement in visibility impacts associated with this control technology.

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 SO_2 CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	SO_2 Reduced	Capital Cost	Annual Capital Cost	Annual Direct O&M	Annual Indirect O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to Semi-Dry Scrubbing	Incremental Visibility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 -Semi-Dry Scrubbing	19,550	0.06	55,269,197	1,658	17,892	335,133,908	27,007,236	8,837,861	16,282,987	52,128,084	2,913	-	0.813
SN-02 - Semi-Dry Scrubbing	17,167	0.06	54,138,841	1,624	15,543	335,133,908	27,007,236	8,859,823	16,282,987	52,150,047	3,355	-	0.767
SN-01 -Wet Scrubbing	19,550	0.04	55,269,197	1,105	18,445	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	3,626	26,701	0.021
SN-02 - Wet Scrubbing	17,167	0.04	54,138,841	1,083	16,084	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	4,158	27,218	0.021

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for semi-dry scrubbing is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 5-5 and 5-6). The incremental visibility improvement for wet scrubbing is the difference between the maximum improvement due to wet scrubbing less the maximum visibility improvement from dry scrubbing (See Tables 5-5 and 5-6).

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

As illustrated in Table 5-3 and in Section 5.5 below, wet scrubbing is expected to achieve approximately the same level of visibility improvement as the proposed dry scrubbing technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Such impacts include a potential increase in particulate and sulfuric acid (H_2SO_4) mist emissions. In addition, wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 does not impact the annualized capital costs for either semi-dry scrubbing or wet scrubbing because the useful life of the units is anticipated to be at least as long as the capital cost recovery period, which is 30 years based on the recovery period documented for wet scrubbers for acid gas in the EPA's Control Cost Manual.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02

A final impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the controlled emission rates. Section 4 of this report documents the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with semi-dry and wet scrubbing, the controlled emission rates associated with each control technology were modeled using CALPUFF. The SO_2 emission rates associated with wet and semi-dry scrubbers were calculated as follows:

$$P * HI = 537.00 \text{ lb/hr}$$

Where:
P for wet scrubber = 0.04 lb/MMBtu
P for semi-dry scrubber = 0.06 lb/MMBtu
HI (hourly heat input) = 8,950 MMBtu/hr

Table 5-4 summarizes the lb/hr emission rates that were modeled to reflect the addition of wet and semi-dry scrubbers on SN-01 and SN-02. One important thing to note is the ammonium sulfate emission rate indicated for wet scrubbers is higher than the ammonium sulfate emission rate indicated for semi-dry scrubbers. For all PM species other than ammonium sulfate, the NPS speciation spreadsheets were relied upon to determine emission rates for PM species. For ammonium sulfate, the approach described below was used. The NO_X emission rates were modeled at the baseline rates.

Sulfur in the fuel reacts with oxygen during the combustion process to form SO_2. Some of the SO_2 is further oxidized to SO_3, which is a precursor to sulfuric acid (H_2SO_4). Sulfuric acid can react with ammonia to cause primary emissions of ammonium sulfate. According to both FGD suppliers and the EPA, wet scrubbers have less affinity for SO_3 and typically capture between 25-50% of the SO_3.[23] Since SO_3 can lead to the formation of H_2SO_4, which leads to the formation of ammonium sulfates, the higher level of SO_3 control for semi-dry scrubbers will result in lower H_2SO_4 emissions and thus lower ammonium sulfate emissions. The ammonium sulfate emission rates for semi-dry scrubbers shown in Table 5-4 were determined assuming the reduction in ammonium sulfate (SO_4) is proportional to the reduction in SO_2 from the baseline case to the controlled case (95%). The ammonium sulfate emission rates for wet scrubbers shown in Table 5-4 were determined assuming a 50% reduction in SO_4 from the baseline case to the controlled case.

TABLE 5-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS

Source	SO_2 (lb/hr)	SO_4[1] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – Semi-Dry Scrubbing	537.0	2.7	3,001.4	1.0	1.0	0.7	0.0	5.4
SN-02 – Semi-Dry Scrubbing	537.0	2.8	3,527.4	1.0	1.0	0.7	0.0	5.6
SN-01 – Wet Scrubbing	358.0	18.4	3,001.4	6.7	6.5	4.6	0.2	36.4
SN-02 – Wet Scrubbing	358.0	18.4	3,527.4	6.7	6.5	4.6	0.2	36.4

[1] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing visibility impacts and the visibility impacts based on wet and semi-dry scrubbing, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 5-5 and Table 5-6.

[23] In addition, according to the EPA Technical Support Document for the Rules to Reduce Interstate Transport of Fine Particulate Matter and Ozone, "More than 90 percent of SO_3/H_2SO_4 is removed in a dry FGD, while up to about 50 percent removal occurs in a wet FGD system." http://www.epa.gov/cair/pdfs/0053-2263.pdf

TABLE 5-5 SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
Semi-Dry Scrubber	1.961	0.815	27	0.763	0.378	6	0.698	0.358	5	0.841	0.267	2
Post Control Improvement†	*2.233*	*0.813*	*79*	*1.576*	*0.762*	*71*	*1.532*	*0.683*	*56*	*0.728*	*0.620*	*54*
Wet Scrubber	1.941	0.794	26	0.774	0.350	6	0.687	0.360	3	0.838	0.271	1
Incremental Improvement over Semi-Dry Scrubber†	*0.020*	*0.021*	*1*	*-0.011*	*0.028*	*0*	*0.011*	*-0.002*	*2*	*0.003*	*-0.004*	*1*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 5-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-02 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
Semi-Dry Scrubber	2.245	0.941	35	0.888	0.418	11	0.803	0.415	6	0.977	0.310	3
Post Control Improvement†	*2.192*	*0.754*	*77*	*1.497*	*0.767*	*69*	*1.460*	*0.645*	*59*	*0.724*	*0.593*	*54*
Wet Scrubber	2.226	0.920	35	0.899	0.405	10	0.792	0.416	6	0.974	0.315	3
Post Control Improvement over Semi-Dry Scrubber†	*0.019*	*0.021*	*0*	*-0.011*	*0.013*	*1*	*0.011*	*-0.001*	*0*	*0.003*	*-0.005*	*0*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-5 and Table 5-6, based on visibility predictions from the CALPUFF modeling system, the operation of a semi-dry scrubber achieving 0.06 lb/MMBtu will result in up to a 0.813 Δdv improvement (depending on the Class I area) to the existing 98th percentile day of visibility impairment attributable to SN-01 and up to 0.767 Δdv improvement for SN-02. By comparison, wet scrubbing achieving 0.04 lb/MMBtu only adds up to an additional 0.028 Δdv improvement for SN-01 and up to 0.021 Δdv improvement for SN-02.

For convenience, Tables 5-7 and 5-8 provide a condensed summary of the predicted improvements to visibility impairment alongside the estimated control costs. While the application of wet scrubbing may be able to achieve a nominally lower outlet SO_2 emission rate, there is essentially no incremental visibility benefit of going from semi-dry scrubbing to wet scrubbing. Further, in some cases, CALPUFF predicts worse visibility impairment for wet scrubbing as opposed to semi-dry scrubbing. This is likely due to the higher SO_4 emissions associated with wet vs dry scrubbing. Overall, the very small differences in predicted visibility impacts likely fall within the relative accuracy level of CALPUFF's modeling results. Given that wet scrubbing requires a significantly higher capital investment and is more expensive from an incremental cost effectiveness standpoint than semi-dry scrubbing, it cannot be justified as BART at SN-01 and SN-02. The adverse non-air environmental impacts from wet scrubbing also make it a less desirable control technology.

TABLE 5-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-01	Semi-dry Scrubbing	0.06	93%	17,892.26	335,133,908	52,128,084	2,913	-	Caney Creek	1.628	0.815	0.813	-	106	27	-
									Hercules-Glades	1.041	0.358	0.683	-	61	5	-
									Mingo	0.887	0.267	0.620	-	56	2	-
									Upper Buffalo	1.140	0.378	0.762	-	77	6	-
SN-01	Wet Scrubbing	0.04	95%	18,444.95	389,496,052	66,885,535	3,626	26,701	Caney Creek	1.628	0.794	0.834	0.021	106	26	1
									Hercules-Glades	1.041	0.360	0.681	-0.002	61	3	2
									Mingo	0.887	0.271	0.616	-0.004	56	1	1
									Upper Buffalo	1.140	0.350	0.790	0.028	77	6	0

TABLE 5-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-02	Semi-dry Scrubbing	0.06	92%	15,542.83	335,133,908	52,150,047	3,355	-	Caney Creek	1.695	0.941	0.754	-	112	35	-
									Hercules-Glades	1.060	0.415	0.645	-	65	6	-
									Mingo	0.903	0.310	0.593	-	57	3	-
									Upper Buffalo	1.185	0.418	0.767	-	80	11	-
SN-02	Wet Scrubbing	0.04	95%	16,084.22	389,496,052	66,885,535	4,158	27,218	Caney Creek	1.695	0.920	0.775	0.021	112	35	0
									Hercules-Glades	1.060	0.416	0.644	-0.001	65	6	0
									Mingo	0.903	0.315	0.588	-0.005	57	3	0
									Upper Buffalo	1.185	0.405	0.780	0.013	80	10	1

5.6 PROPOSED BART FOR SO_2 FOR SN-01 AND SN-02

Entergy is proposing that the SO_2 BART emission level for SN-01 and SN-02 be 0.06 lb/MMBtu based on the installation and operation of a semi-dry scrubber or whatever technology may become available to achieve that level of control. EPA has previously agreed that "this [SDA] technology is BART for these two units."[24] Entergy is proposing to meet this limit on a 30-day rolling average basis. This emission level provides for a very small compliance margin considering the variability of the coal content for the White Bluff units; therefore, the proposed 30-day averaging period and compliance demonstration method is critical. Compliance will be demonstrated using data from the existing CEMS.

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

EPA has agreed with similar and even less stringent SO_2 BART determinations in other states. For example, in Oklahoma,[25] EPA agreed with the BART determination of 0.06 lb/MMBtu achieved through use of dry scrubbers for similar boilers, based on the minimal visibility improvement associated with wet vs dry scrubbing.. In Nebraska[26] at GGS, BART for SO_2 was also determined to be 0.06 lb/MMBtu achieved through the use of dry scrubbers. These similar units provide a good comparison of emission levels achievable through similar control technology.

Other BART determinations have resulted in higher emission limitations. For example, in Alabama,[27] a smaller EGU was allowed an emission limitation of 0.47 lb/MMBtu through use of flue solvent injection or comparable technologies. In Arizona,[28] SO_2 BART was determined to be in the range of 0.08 – 0.15 lb/MMBtu from existing wet scrubbers. An EGU in Colorado[29] has a proposed BART emission rate of 0.13 lb/MMBtu through use of dry scrubbing. A lower emission rate of 0.09 lb/MMBtu was evaluated and determined not reasonable due to the minimal visibility improvement projected as compared to the higher costs of scrubbing to meet the lower rate.

In other determinations, such as Illinois,[30] the control technology was not stated in the BART determination but the SO_2 rate determined to be BART was in the range of 0.11 – 0.23 lb/MMBtu, dependent upon boiler type and averaging considerations. SO_2 BART in Kansas[31] was achieved through "scrubbing" with an emission limitation of 0.10 lb/MMBtu for one boiler and through wet scrubbing with an emission limitation of 0.15 lb/MMBtu for another. An EGU in Montana[32] similar to Entergy's SN-01 and SN-02 has a BART emission rate of 0.08 lb/MMBtu.

---

[24] November 25, 2009, letter from Mr. Jeff Robinson, EPA, to Mr. Tom Rheaume, ADEQ.
[25] 77 Fed. Reg. 16168 (March 22, 2011).
[26] 77 Fed. Reg. 40150 (July 6, 2012).
[27] 77 Fed. Reg. 11937 (February 28, 2012).
[28] 77 Fed. Reg. 42834 (July 20, 2012).
[29] 77 Fed. Reg. 18052 (March 26, 2012).
[30] 77 Fed. Reg. 3966 (January 26, 2012).
[31] 77 Fed. Reg. 52604 (August 23, 2011).
[32] 77 Fed. Reg. 23988 (April 20, 2012).

5.7 SO_2 BART FOR SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[33]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations for similar boilers in other states, such as the auxiliary boiler at the Basin Electric Power Cooperative's Leland Olds Station located in North Dakota or the auxiliary boiler at the Golden Valley Electric Association's Healy Power plant in Fairbanks, Alaska.

[33] *See* Table 4-4

6. NO_X BART EVALUATION

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as SN-01 and SN-02, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore, baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1 for SN-01 and SN-02.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA) or separated OFA (SOFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_X Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1. Control ranges were developed using a combination of literature control ranges and efficiencies. Because many controlled emissions rates from literature values were higher

than the baseline NO_X rate at SN-01 and SN-02, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.2.1 COMBUSTION CONTROLS

6.2.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_X formation. However, vendor-specific review of the White Bluff boilers has concluded that NO_X reduction efficiency data for coal-fired units with FGR are limited. The amount of NO_X reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NO_X rather than fuel NO_X. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NO_X control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

6.2.1.2 OVERFIRE AIR (OFA) / SEPARATED OVERFIRE AIR (SOFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

SOFA refers to a system wherein the OFA is injected in a separate wind box mounted above the main wind box in order to achieve greater separation from the combustion zone resulting in more effective NO_X suppression. SOFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%,[34] or 0.28-0.32 lb/MMBtu from SN-01 and SN-02. This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[34] *Id.*

6.2.1.3 LOW NO_X BURNERS (LNB)

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[35] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When combined with SOFA, the estimated NO_X emission rate is 0.15 lb/MMBtu.[36] LNB systems with SOFA are technically feasible for the control of NO_X from SN-01 and SN-02.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with LNB and OFA, the estimated NO_X emission rate is 0.055 lb/MMBtu.[37] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea)

---

[35] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

[36] 2012 S&L NOx Study.

[37] *Id.*, this rate includes consideration of normal fluctuations which may occur over a 30-day compliance period.

react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with LNB/OFA, the estimated NO_X emission rate is 0.13 lb/MMBtu.[38] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[38] *Id.*

6.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section.

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Controlled Level for SN-01 and SN-02 (lb/MMBtu)
SOFA	0.28-0.32
LNB/SOFA	0.15
LNB/SOFA + SNCR	0.13
LNB/SOFA + SCR	0.055

Current NO_X emissions are approximately 0.31 lb/MMBtu from SN-01 and approximately 0.36 lb/MMBtu from SN-02. Based on evaluations by S&L, it is believed that combustion controls such as LNB in combination with SOFA will achieve a NO_X level of 0.15 lb/MMBtu for SN-01 and SN-02.[39] Further, it is believed that the addition of SCR to LNB/SOFA will achieve a NO_X level of approximately 0.055 lb/MMBtu at each unit and LNB/SOFA + SNCR will achieve a level of 0.13 lb/MMBtu at each unit.

6.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance;
- Energy impacts;
- Non-air quality impacts; and
- The remaining useful life of the source.

6.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR were estimated for the cost analysis.

[39] EPA established presumptive SO_2 and NO_X controls for coal-fired EGUs in the BART rule. For dry bottom tangentially-fired EGUs, the presumptive NO_X limit is 0.15 lb/MMBtu. (Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.") 77 FR 39134 (July 6, 2005).

Control Costs

Control costs were calculated using vendor capital and operating cost estimates specific to the units. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs.

The details of the capital and operating cost estimates are provided in Appendix A of this report.

It should be noted that the capital costs presented for the various NO_x control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a NOx controls installation, during the construction phase, which can take many months to several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rates were the average rates from 2009-2011, as reported by Entergy in their air emission inventories. The controlled annual emission rate is based on the lb/MMBtu level believed to be achievable from the control technology multiplied by the future annual input to the boiler in MMBtu/yr. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001to 2003 for each boiler. This was the same approach that was used to estimate future annual heat input in the review of SO_2 controls

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analysis was also performed to show the incremental increase in costs between LNB/SOFA + SCR and an LNB/SOFA system, as well as between LNB/SOFA + SNCR and LNB/SOFA. The costs effectiveness analysis is summarized in Table 6-3.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of

NO_X removed based on the use of combustion control technology.[40] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[41]

Table 6-3 indicates that the cost effectiveness of LNB/SOFA is approximately $375 per ton of NO_X removed. Installing LNB/SOFA would reduce NO_X emissions by more than 50%. By contrast, the incremental cost effectiveness of adding SNCR to LNB/SOFA is approximately $10,000/ton per unit. Similarly, the incremental cost of adding SCR to LNB/SOFA is approximately $7,250-$8,000/ton per unit.

Table 6-3 also demonstrates the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. As Table 6-3 clearly shows, LNB/SOFA + SNCR offers very little visibility improvement over LNB/SOFA alone (~0.03 dv). The addition of SCR incrementally improves visibility over LNB/SOFA by only approximately 0.1 dv at an annual cost of well over $20,000,000 per unit. Such a large cost cannot be justified by the negligible visibility improvement provided by SCR.

[40] *Id.* at 39134-39135.
[41] *Id.*

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to LNB/SOFA	Incremental Visbility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 LNB/SOFA	7,249.23	0.15	55,269,197	4145.19	3104.04	10,461,206	843,031	142,000	177,887	1,162,918	375	-	0.176
SN-01 LNB/SOFA/SNCR	7,249.23	0.13	55,269,197	3592.50	3656.73	21,371,325	1,722,238	311,000	4,538,000	6,571,238	1,797	9,785	0.024
SN-01 LNB/SOFA/SCR	7,249.23	0.055	55,269,197	1519.90	5729.33	230,329,138	18,561,397	608,000	2,836,000	22,005,397	3,841	7,939	0.093
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-02 LNB/SOFA	8,185.33	0.15	54,138,841	4060.41	4124.91	14,488,206	1,167,552	142,000	170,838	1,480,391	359	-	0.225
SN-02 LNB/SOFA/SNCR	8,185.33	0.13	54,138,841	3519.02	4666.30	25,398,325	2,046,760	311,000	4,542,000	6,899,760	1,479	10,010	0.033
SN-02 LNB/SOFA/SCR	8,185.33	0.055	54,138,841	1488.82	6696.51	206,747,898	16,661,070	608,000	2,858,000	20,127,070	3,006	7,251	0.102

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for LNB/SOFA is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 6-5 and 6-6). The incremental visibility improvement for LNB/SOFA/SNCR and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from LNB/SOFA (See Tables 6-5 and 6-6).

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-3 and in Section 6.5 below, SCR and SNCR systems are capable of achieving additional NO_X mass emission reductions in comparison to combustion controls such as LNB/SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 are sufficiently long such that it does not affect the BART analysis.

6.5 Evaluation of Visibility Impact of Feasible NO_X Controls

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR. Section 4 of this report documented the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with LNB/SOFA system is 0.15 lb/MMBtu; the controlled emission level associated with SOFA + SNCR is 0.13 lb/MMBtu; and the controlled emission level associated with LNB/SOFA + SCR systems is 0.055 lb/MMBtu for each unit. These levels were multiplied by the maximum heat input to derive the hourly emission rates used in the modeling.

Table 6-4 summarizes the NO_X emission rates that were modeled to reflect the LNB/SOFA, LNB/SOFA + SNCR, and LNB/SOFA + SCR. The emission rates for the other pollutants shown in Tables 6-4 are the same as in the baseline modeling.

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT NO_X CONTROLS

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – LNB/SOFA	7,763.5	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-02 – LNB/SOFA	7,825.1	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-01 - LNB/SOFA + SNCR	7,763.5	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SNCR	7,825.1	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-01 – LNB/SOFA + SCR	7,763.5	36.8	492.3	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SCR	7,825.1	36.8	492.3	40.4	31.1	9.2	1.2	118.6

Tables 6-5 and 6-6 provide a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 and SN-02, respectively, in all affected Class I areas, including the maximum modeled visibility impact, the 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-5. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
LNB/OFA	3.465	1.462	89	2.243	1.039	62	2.175	0.865	48	1.168	0.849	45
Post Control Improvement	*0.729*	*0.166*	*17*	*0.096*	*0.101*	*15*	*0.055*	*0.176*	*13*	*0.401*	*0.038*	*11*
LNB/OFA + SNCR	3.386	1.428	86	2.233	1.029	62	2.170	0.844	47	1.146	0.842	44
Incremental Improvement Over LNB/SOFA	*0.079*	*0.034*	*3*	*0.010*	*0.01*	*0*	*0.005*	*0.021*	*1*	*0.022*	*0.007*	*1*
LNB/OFA + SCR	3.089	1.359	73	2.196	0.991	59	2.148	0.832	45	1.132	0.817	38
Incremental Improvement Over LNB/OFA	*0.376*	*0.103*	*16*	*0.047*	*0.048*	*3*	*0.027*	*0.033*	*3*	*0.036*	*0.032*	*7*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 6-6. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-02 (2001-2003)

\	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
LNB/SOFA	3.483	1.47	91	2.258	1.046	62	2.191	0.870	48	1.174	0.856	45
Post Control Improvement	*0.954*	*0.225*	*21*	*0.127*	*0.139*	*18*	*0.072*	*0.190*	*17*	*0.527*	*0.047*	*12*
LNB/SOFA + SNCR	3.404	1.437	87	2.248	1.035	62	2.185	0.849	47	1.152	0.849	45
Incremental Improvement Over LNB/SOFA	*0.079*	*0.033*	*4*	*0.010*	*0.011*	*0*	*0.006*	*0.021*	*1*	*0.022*	*0.007*	*0*
LNB/SOFA + SCR	3.107	1.368	75	2.211	0.997	59	2.164	0.838	45	1.138	0.823	39
Incremental Improvement Over LNB/SOFA	*0.376*	*0.102*	*16*	*0.047*	*0.049*	*3*	*0.027*	*0.032*	*3*	*0.036*	*0.033*	*6*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

In light of the very small incremental visibility benefit and the high marginal cost, SNCR cannot be considered BART for either SN-01 or SN-02. As shown in Table 6-5 and Table 6-6, based on visibility predictions from the CALPUFF modeling system, the operation of a LNB/SOFA will result in up to a 0.176 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to SN-01 and up to 0.225 Δdv improvement for SN-02. There is essentially zero visibility improvement due to including SNCR, with a modeled change of approximately 0.03 Δdv for both units. The addition of SCR would produce a modeled improvement of only 0.103 Δdv for Unit 1 and 0.102 Δdv for Unit 2 over LNB/SOFA alone.

Tables 6-7 and 6-8 provide a condensed summary of these predicted improvements alongside the estimated control costs. The incremental benefit of going from LNB/SOFA to either LNB/SOFA + SCNR or LNB/SOFA + SCR is clearly not justified. The control technologies are very expensive in terms of initial capital investment and are prohibitively more expensive from an incremental cost effectiveness standpoint than LNB/SOFA alone.

TABLE 6-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-01	LNB/SOFA	0.15	51%	3,104.04	10,461,206	1,162,918	375	-	Caney Creek	1.628	1.462	0.166	-	106	89	-
									Hercules-Glades	1.041	0.865	0.176	-	61	48	-
									Mingo	0.887	0.849	0.038	-	56	45	-
									Upper Buffalo	1.140	1.039	0.101	-	77	62	-
SN-01	LNB/SOFA + SNCR	0.13	58%	3,656.73	21,371,325	6,571,238	1,797	9,785	Caney Creek	1.628	1.428	0.200	0.034	106	86	3
									Hercules-Glades	1.041	0.844	0.197	0.021	61	47	1
									Mingo	0.887	0.842	0.045	0.007	56	44	1
									Upper Buffalo	1.140	1.029	0.111	0.010	77	62	0
SN-01	LNB/SOFA + SCR	0.055	82%	5,729.33	230,329,138	22,005,397	3,841	7,939	Caney Creek	1.628	1.359	0.269	0.103	106	73	16
									Hercules-Glades	1.041	0.832	0.209	0.033	61	45	3
									Mingo	0.887	0.817	0.070	0.032	56	38	7
									Upper Buffalo	1.140	0.991	0.149	0.048	77	59	3

TABLE 6-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-02	LNB/SOFA	0.15	58%	4,124.91	14,488,206	1,480,391	359	-	Caney Creek	1.695	1.470	0.225	-	112	91	-
									Hercules-Glades	1.060	0.870	0.190	-	65	48	-
									Mingo	0.903	0.856	0.047	-	57	45	-
									Upper Buffalo	1.185	1.046	0.139	-	80	62	-
SN-02	LNB/SOFA + SNCR	0.13	63%	4,666.30	206,747,898	6,899,760	1,479	10,010	Caney Creek	1.695	1.437	0.258	0.033	112	87	4
									Hercules-Glades	1.060	0.849	0.211	0.021	65	47	1
									Mingo	0.903	0.849	0.054	0.007	57	45	0
									Upper Buffalo	1.185	1.035	0.150	0.011	80	62	0
SN-02	LNB/SOFA + SCR	0.055	85%	6,696.51	206,747,898	20,127,070	3,006	7,251	Caney Creek	1.695	1.368	0.327	0.102	112	75	16
									Hercules-Glades	1.060	0.838	0.222	0.032	65	45	3
									Mingo	0.903	0.823	0.080	0.033	57	39	6
									Upper Buffalo	1.185	0.997	0.188	0.049	80	59	3

6.6 Proposed BART for NO_X for SN-01 and SN-02

If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

With full consideration of all five factors outlined by EPA for BART determinations, Entergy proposes a BART emission level of 0.15 lb/MMBtu on a 30-day rolling average basis, achievable through use of LNB/SOFA at SN-01 and SN-02. Compliance will be demonstrated using data from the existing CEMS. This determination is consistent with the BART determinations approved by EPA in Oklahoma, including the determinations for OG&E Seminole Units 1, 2, and 3 that combustion controls achieving 30-day rolling average NO_X levels of 0.203 lb/MMBtu, 0.212 lb/MMBtu, and 0.164 lb/MMBtu, respectively, constitute BART and the determination for OG&E Sooner Units 1 and 2, OG&E Muskogee Unit 4, and AEP/PSO Northeastern Units 3 and 4 that combustion controls achieving a 30-day rolling average NO_X level of 0.15 lb/MMBtu constitute BART.[42]

6.7 Proposed BART for NO_X for SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[43]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, *no controls* is the NO_X BART determination for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

[42] 77 Fed. Reg. 16168 (March 22, 2011).

[43] *See* Table 4-4

7. PM_{10} BART EVALUATION

EPA's Approval and Promulgation of Implementation Plans, published March 12, 2012, determined that the currently installed ESP is BART for PM_{10} for SN-01 and SN-02.

> The federally enforceable operating air permit states the PM emissions from the two units are controlled with ESPs and requires that the two units comply with a PM emission standard of 0.10 lb/MMBtu. Since we have found that the visibility impact of the source due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and subbituminous coal firing scenarios is the existing PM emission limit for Units 1 and 2.[44]

As such, no further PM_{10} analysis has been conducted.

Section 4 of this report summarized the baseline visibility impairment attributable to SN-01, SN-02 and SN-05. Table 4-4 demonstrates that SN-05 does not contribute to a single day of visibility impairment greater than 0.5 Δdv. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

[44] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 FR 14658 (March 12, 2012).

APPENDIX A

SO_2 AND NO_X CONTROL COST CALCULATIONS

Semi-Dry Scrubber Capital and O&M Cost Estimate			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2009-2011		7361	7401
Capital Costs[1]		**Unit 1**	**Unit 2**
Total Contractor Costs (2012 Dollars)		$174,854,437	$174,854,437
Total Contractor Costs (2010 Dollars):		$156,974,274	$156,974,274
FGD Equipment (2010 Dollars)		$57,649,982	$57,649,982
FGD Materials (2010 Dollars)		$14,840,928	$14,840,928
FGD Contractor Labor (2010 Dollars)		$63,607,654	$63,607,654
FGD Contractor Contingency (2010 Dollars)		$20,875,711	$20,875,711
Total Balance of Plant (BOP) Direct Costs (2012 Dollars)		$118,537,729	$118,537,729
Balance of Plant (BOP) Equipment (2012 Dollars)		$24,816,321	$24,816,321
BOP Materials (2012 Dollars)		$26,464,135	$26,464,135
BOP Labor (2012 Dollars)		$67,257,273	$67,257,273
Balance of Plant (BOP) Indirect Costs (2012 Dollars)		$8,733,104	$8,733,104
Misc Contractor Labor (2012 Dollars)		$4,583,719	$4,583,719
Misc Contractor Labor (2010 Dollars)[2]		$4,115,000	$4,115,000
Entergy Internal Costs (2012 Dollars)		$20,076,644	$20,076,644
Entergy Internal Costs (2010 Dollars)[3]		$18,023,659	$18,023,659
Capital suspense (2010 Dollars)		$7,494,603	$7,494,603
Capital suspense (2012 Dollars)		$8,348,276	$8,348,276
CEPCI 2008		530.7	530.7
CEPCI 2010		533	533
CEPCI 2012 (January)		593.6	593.6
Total Capital Investment		$335,133,908	$335,133,908
Capital Recovery Factor (CRF)[4]		0.08	0.08
Annual Costs[5]			
CEPCI 2008		530.7	530.7
Direct Annual Costs (2012 Dollars)		$8,837,861	$8,859,823
Direct Annual Costs (2008 Dollars)		$7,901,369	$7,921,004
Operating Labor and Materials (2008 Dollars)		$4,287,845	$4,287,845
Water, Waste & Bag Replacement Costs $/MWh (2008 Dollars)		0.29	0.29
Lime Costs $/MWh (2008 Dollars)		0.75	0.75
Water, Waste, Bag Replacement and Lime Costs $/MWh (2008 Dollars)		1.04	1.04
Anticipated Yearly MWh[6]		3,474,543	3,493,423
Water, Waste, Bag Replacement and Lime Costs (2008 Dollars)		3,613,525	3,633,160
Indirect Annual Costs (IC) (2012 Dollars):		$43,290,224	$43,290,224
Overhead (2008 Dollars)	60% of total labor and materials costs	$2,572,707	$2,572,707
Overhead (2012 Dollars)		$2,877,631	$2,877,631
Administrative charges (2012 Dollars)	2% of TCI	$6,702,678	$6,702,678
Property Tax (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Insurance (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Capital recovery (2012 Dollars)	CRF* TCI	$27,007,236	$27,007,236
Total Annual Costs		$52,128,084	$52,150,047

1: The capital costs are based on contractor estimates provided by Sargent & Lundy (S&L) to Entergy in 2010 and other estimates compiled by Entergy in 2008. Both the 2010 cost from S&L and the 2008 cost estimated by Entergy were scaled to reflect 2012 dollars.

2: Misc contract labor includes permitting and regulatory support.

3: Entergy internal costs include labor, travel, and loader costs.

4: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr life, 7% interest

5: The O&M cost estimates are based on the Sargent & Lundy economic model from May 2008. The cost estimates were scaled to reflect 2012 dollars.

6: Anticipated yearly MWh = (944 MW/2 * anticipated annual operating hours) - 13 MWh, where 944 MW is anticipated EIA share for both boilers and 13 MWh is the estimated parsitic load loss estimate due to operation of the control from both boilers.

Wet Scrubber Capital and O&M Cost Estimate[1]			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2001-2003		7361	7401
Capital Costs		**Unit 1**	**Unit 2**
Total Equipment Costs (EC) (2012 Dollars)[2]		$150,037,000	$150,037,000
Purchased Equipment Cost (PEC)	PEC = 1.18 * EC	$177,043,660	$177,043,660
Total Capital Investment (TCI)		$389,496,052	$389,496,052
Capital Recovery Factor (CRF)(2012 Dollars)[3]		0.08	0.08
Annual Costs			
Direct Annual Costs (DC)[4] (2011 Dollars)		$15,734,500	$15,734,500
CECPI 2011		585.7	585.7
CECPI 2012 (January)		593.6	593.6
Direct Annual Costs (DC) (2012 Dollars)		$15,946,729	$15,946,729
Indirect Annual Costs (IC) (2012 Dollars)		$50,938,806	$50,938,806
Overhead (2011 Dollars)	60% of fixed labor and material costs from 2011 S&L conceptual costs	$2,987,400	$2,987,400
Overhead (2012 Dollars)		$3,027,694	$3,027,694
Administrative charges (2012 Dollars)	2% of TCI	$8,733,104	$8,733,104
Property Tax (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Insurance (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Capital recovery	CRF* TCI	$31,388,086	$31,388,086
Total Annual Costs		$66,885,535	$66,885,535

1: The costing method is modeled after the cost method summarized in Section 5.2 of the EPA Control Cost Manual (Post-Combustion Controls, Chapter 1 - Wet Scrubbers for Acid Gas, Table 1.3). Costs for capital suspense have been accounted for and added to the TCI calculated using the Cost Control Manual.

2: The total equipment cost is the sum of the equipment and material costs from the November 30, 2012 Sargent & Lundy conceptual cost estimate.

3: CRF = [I x(1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr life, 7% interest

4: The direct costs include the fixed O&M from the S&L 2011 conceptual costs (operating labor, operating materials, and maintenance materials) plus variable O&M from the S&L 2011 conceptual costs (aux power, bags, cages, lime, limestone, and water)

LNB-SOFA Capital and O&M Cost Estimate		
Operational Data	**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost[1]	10,461,206	14,488,206
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	142,000	142,000
Variable O&M Costs[4]	177,887	170,838
Annualized Capital Cost	843,031	1,167,552
Total Annual Costs	1,162,918	1,480,391

1: The installed capital cost estimates for LNB/OFA are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $7,804,000 and Unit 2 = $11,831,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,589,033 for each unit), and cost for capital suspense (estimated by Entergy to be $955,673 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates were provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M costs are based on the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

LNB-SOFA + SNCR Capital and O&M Cost Estimate

Operational Data	Unit 1	Unit 2
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost [1]	21,371,325	25,398,325
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	311,000	311,000
Variable O&M Costs[4]	4,538,000	4,542,000
Annualized Capital Cost	1,722,238	2,046,760
Total Annual Costs	6,571,238	6,899,760

1: The installed capital cost estimates for LNB/OFA + SNCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $16,290,000 and Unit 2 = $20,317,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $3,223,396 for each unit), and cost for capital suspense (estimated by Entergy to be $1,745,429 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-SOFA + SCR Capital and O&M Cost Estimate

Operational Data	Unit 1	Unit 2
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs[1]	**Unit 1**	**Unit 2**
Installed Capital Cost	230,329,138	206,747,898
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs[3]	**Unit 1**	**Unit 2**
Fixed O&M Costs	608,000	608,000
Variable O&M Costs	2,836,000	2,858,000
Annualized Capital Cost	18,561,397	16,661,070
Total Annual Costs	22,005,397	20,127,070

1: The installed capital cost estimates for LNB/OFA + SCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $202,601,000 and Unit 2 = $178,240,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $450,000 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $6,725,610 for each unit), and cost for capital suspense (estimated by Entergy to be $20,552,528 for Unit 1 and $21,332,288 for Unit 2) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT

The following tables are a continuation of the information presented in Tables 4-2 through 4-4. Tables B-1 through B-3 shows the delta deciview by pollutant in a percentage format.

TABLE B-1. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	79.06	20.65	0.16	0.12
2002	2.111	1.386	30	47.73	47.56	0.82	3.90
2003	4.194	1.13	35	63.88	34.05	0.30	1.76
Upper Buffalo Wilderness							
2001	2.339	1.128	34	74.05	25.72	0.23	0.00
2002	1.544	0.818	18	83.19	16.22	0.34	0.26
2003	1.900	1.140	25	97.99	1.80	0.22	0.00
Hercules Glades Wilderness							
2001	1.737	1.041	28	92.29	7.51	0.21	0.00
2002	1.288	0.617	13	78.93	20.76	0.23	0.08
2003	2.230	0.786	20	88.91	10.87	0.21	0.00
Mingo Wilderness							
2001	1.569	0.887	18	93.36	6.03	0.33	0.28
2002	1.012	0.750	24	56.89	42.59	0.25	0.28
2003	1.114	0.702	14	63.85	34.84	0.38	0.94

TABLE B-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	76.22	23.49	0.16	0.14
2002	2.270	1.481	33	65.10	31.38	0.73	2.80
2003	4.437	1.169	38	50.94	47.45	0.31	1.31
Upper Buffalo Wilderness							
2001	2.385	1.185	35	70.85	28.92	0.23	0.00
2002	1.618	0.846	20	80.92	18.47	0.31	0.30
2003	1.998	1.176	25	81.45	18.30	0.24	0.00
Hercules Glades Wilderness							
2001	1.838	1.060	30	91.12	8.68	0.20	0.00
2002	1.340	0.643	14	76.19	23.50	0.21	0.09
2003	2.263	0.806	21	87.28	12.51	0.21	0.00
Mingo Wilderness							
2001	1.701	0.903	18	92.36	6.99	0.31	0.33
2002	1.031	0.805	25	83.70	16.04	0.22	0.03
2003	1.150	0.750	14	60.22	38.39	0.35	1.04

TABLE B-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	12.12	82.96	1.17	2.01
2002	0.020	0.005	0	13.56	82.08	0.17	3.94
2003	0.036	0.010	0	15.90	76.81	1.12	4.55
Upper Buffalo Wilderness							
2001	0.014	0.004	0	18.99	77.59	1.36	0.12
2002	0.009	0.004	0	22.05	75.33	1.01	0.12
2003	0.013	0.005	0	17.05	74.39	1.76	4.31
Hercules Glades Wilderness							
2001	0.007	0.004	0	15.47	80.65	0.89	1.68
2002	0.006	0.003	0	30.17	65.62	1.50	0.49
2003	0.008	0.004	0	60.26	33.74	2.40	0.03
Mingo Wilderness							
2001	0.009	0.003	0	12.83	84.94	0.89	0.06
2002	0.019	0.008	0	11.22	84.34	1.02	1.91
2003	0.015	0.003	0	21.56	77.36	0.43	0.05

APPENDIX C

CALMET MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

January 23, 2008

Project 083701.0004

TABLE OF CONTENTS

1. INTRODUCTION 1-1
1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND 1-1
1.2 OBJECTIVE 1-2
1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS 1-2

2. CALPUFF MODEL SYSTEM 2-1
2.1 MODEL VERSIONS 2-1
2.2 MODELING DOMAIN 2-1

3. CALMET 3-1
3.1 GEOPHYSICAL DATA 3-1
3.1.1 TERRAIN DATA 3-1
3.1.2 LAND USE DATA 3-2
3.1.3 COMPILING TERRAIN AND LAND USE DATA 3-3
3.2 METEOROLOGICAL DATA 3-3
3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA 3-3
3.2.2 SURFACE METEOROLOGICAL DATA 3-4
3.2.3 UPPER AIR METEOROLOGICAL DATA 3-5
3.2.4 PRECIPITATION METEOROLOGICAL DATA 3-6
3.2.5 BUOY METEOROLOGICAL DATA 3-7
3.3 CALMET CONTROL PARAMETERS 3-8
3.3.1 VERTICAL METEOROLOGICAL PROFILE 3-8
3.3.2 INFLUENCES OF OBSERVATIONS 3-9

APPENDIX A- METEOROLOGICAL STATIONS

APPENDIX B – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 5.8)

APPENDIX C – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 6)

EPA-HQ-2018-002296

LIST OF TABLES

TABLE 1-1. BART-ELIGIBLE SOURCES 1-2

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS 1-2

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS 2-1

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN 3-9

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS A-1

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS A-5

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS A-6

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS A-14

ED_002110_00032338-00067

LIST OF FIGURES

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS 1-3

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN 2-2

FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA 3-2

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA 3-3

FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS 3-5

FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS 3-6

FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS 3-7

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS 3-8

1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

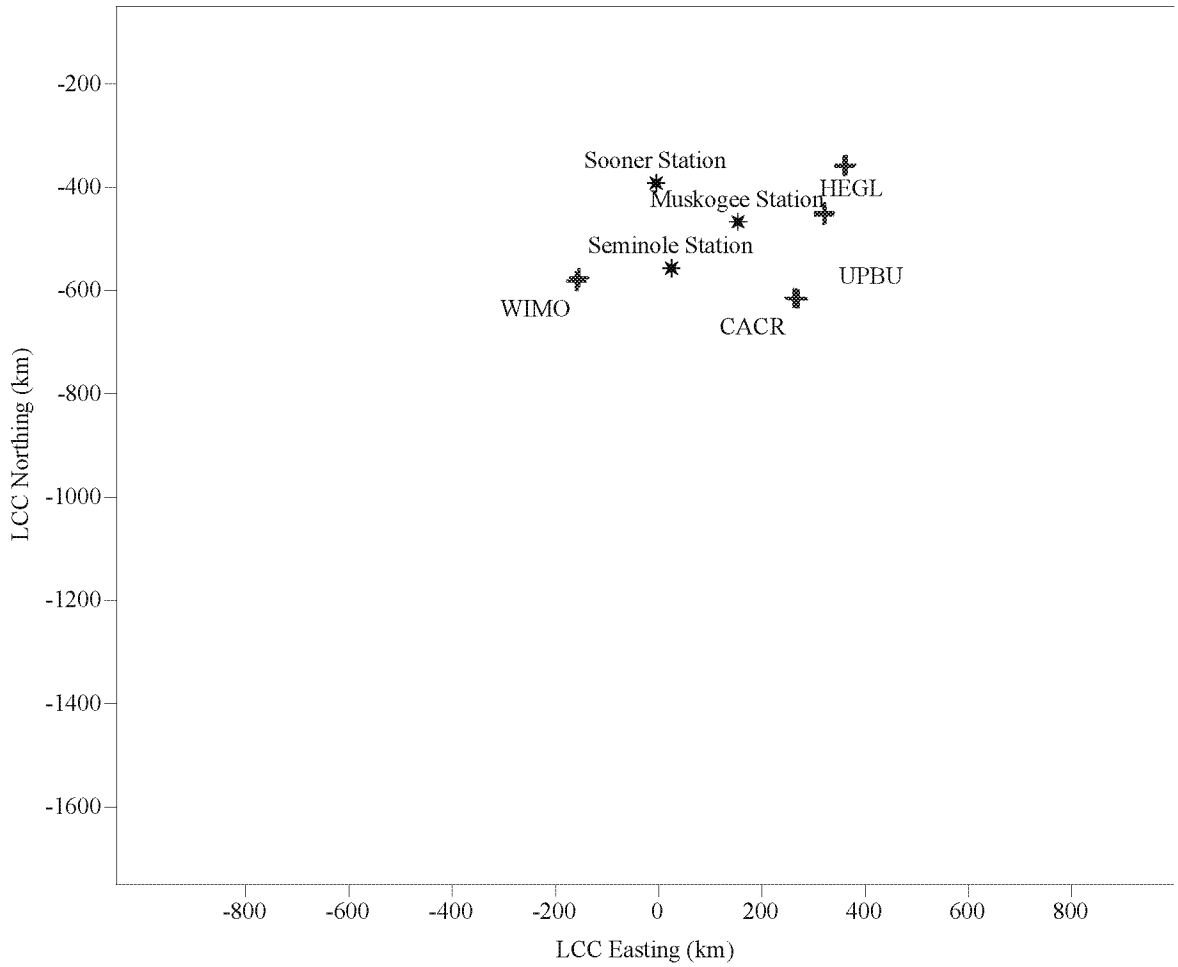
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



+ Class I Areas

2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

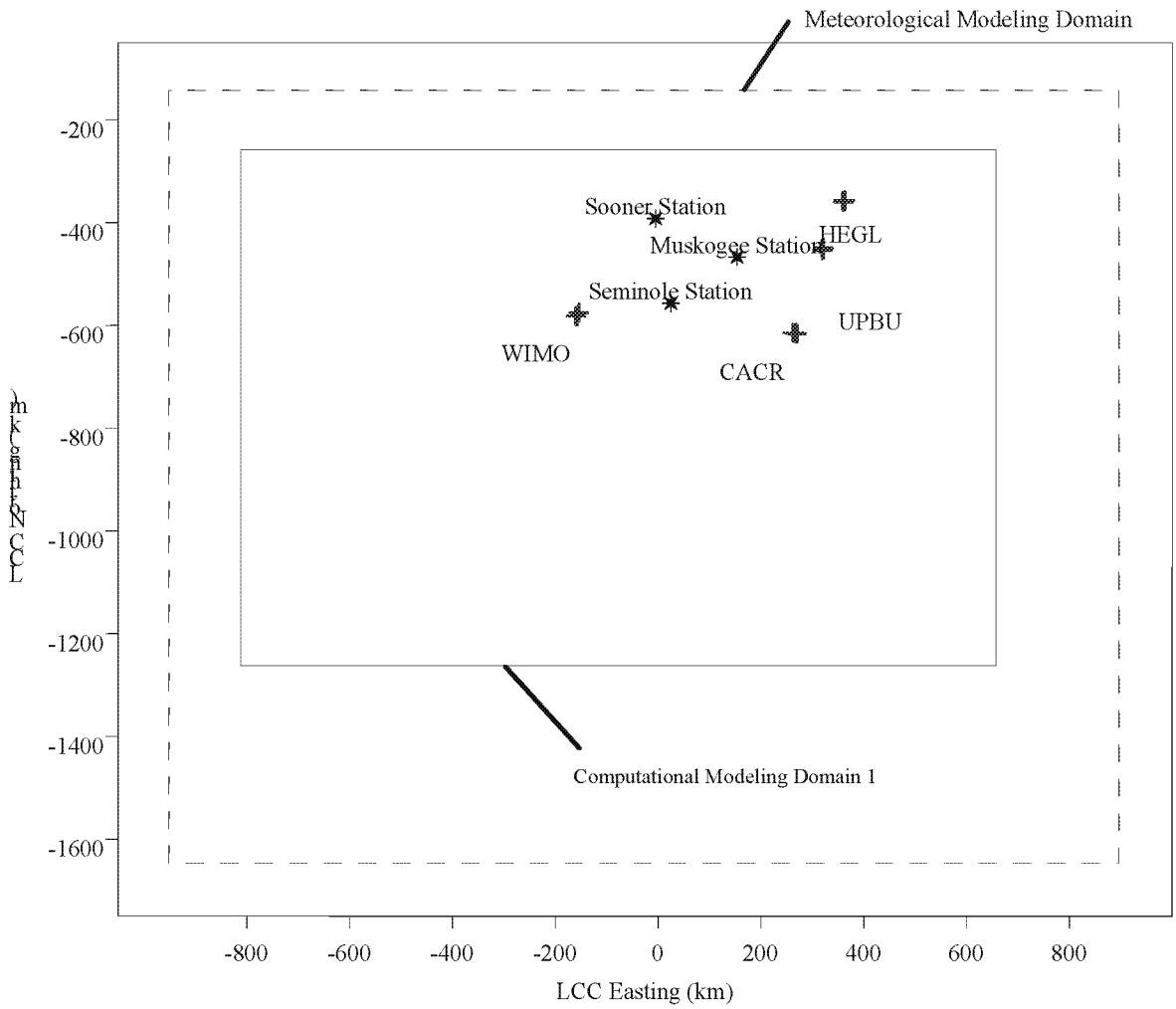
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



Class I Areas

3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

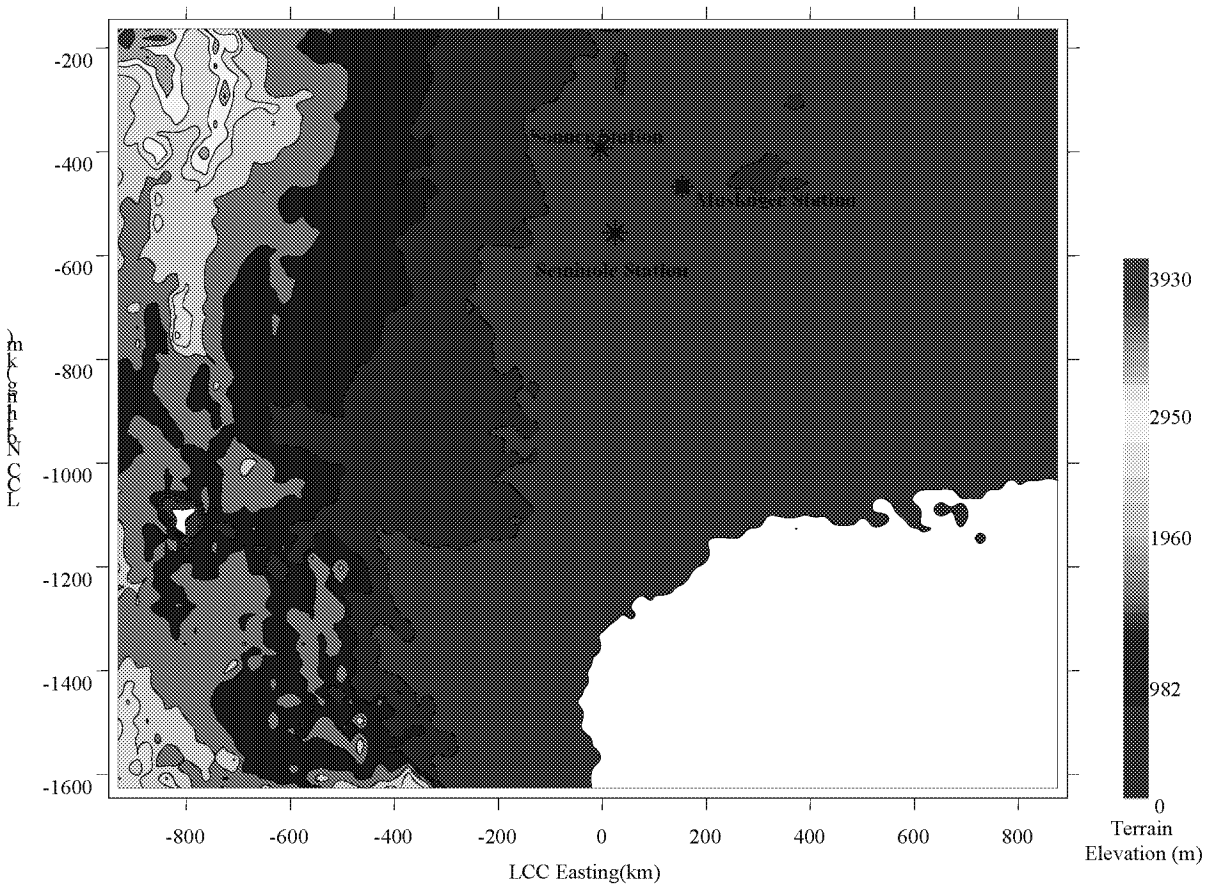
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

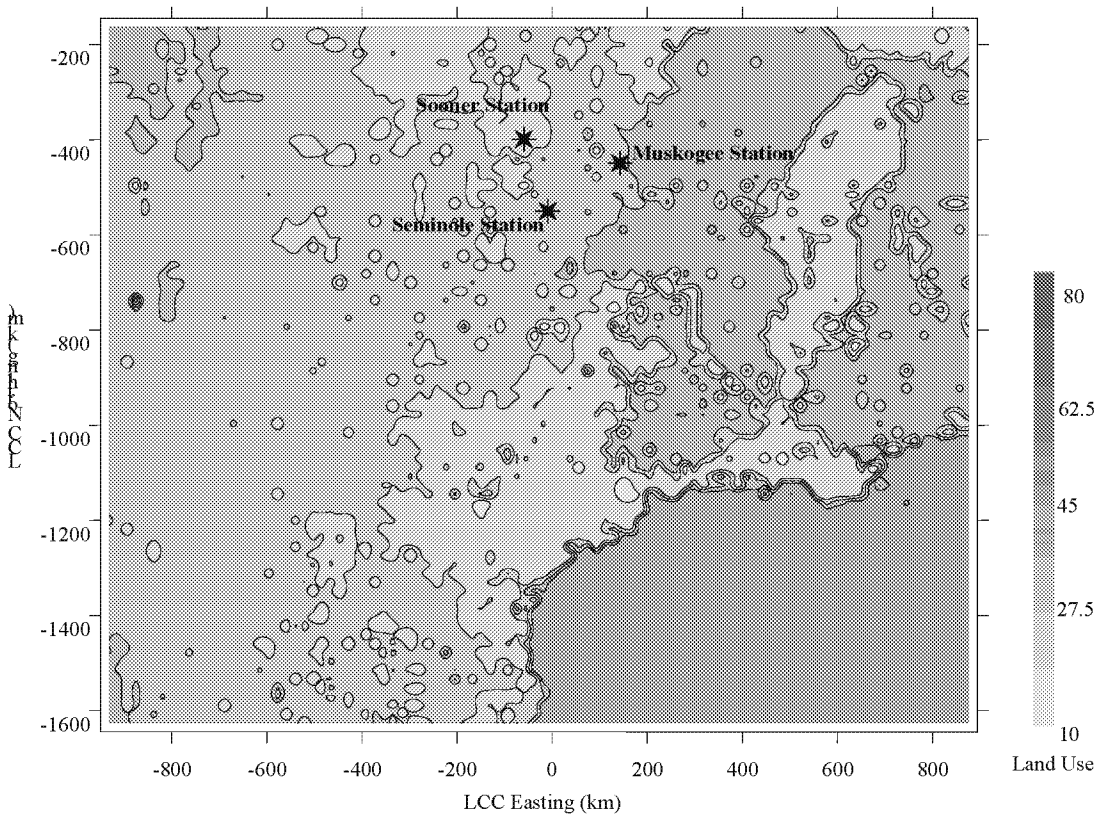
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

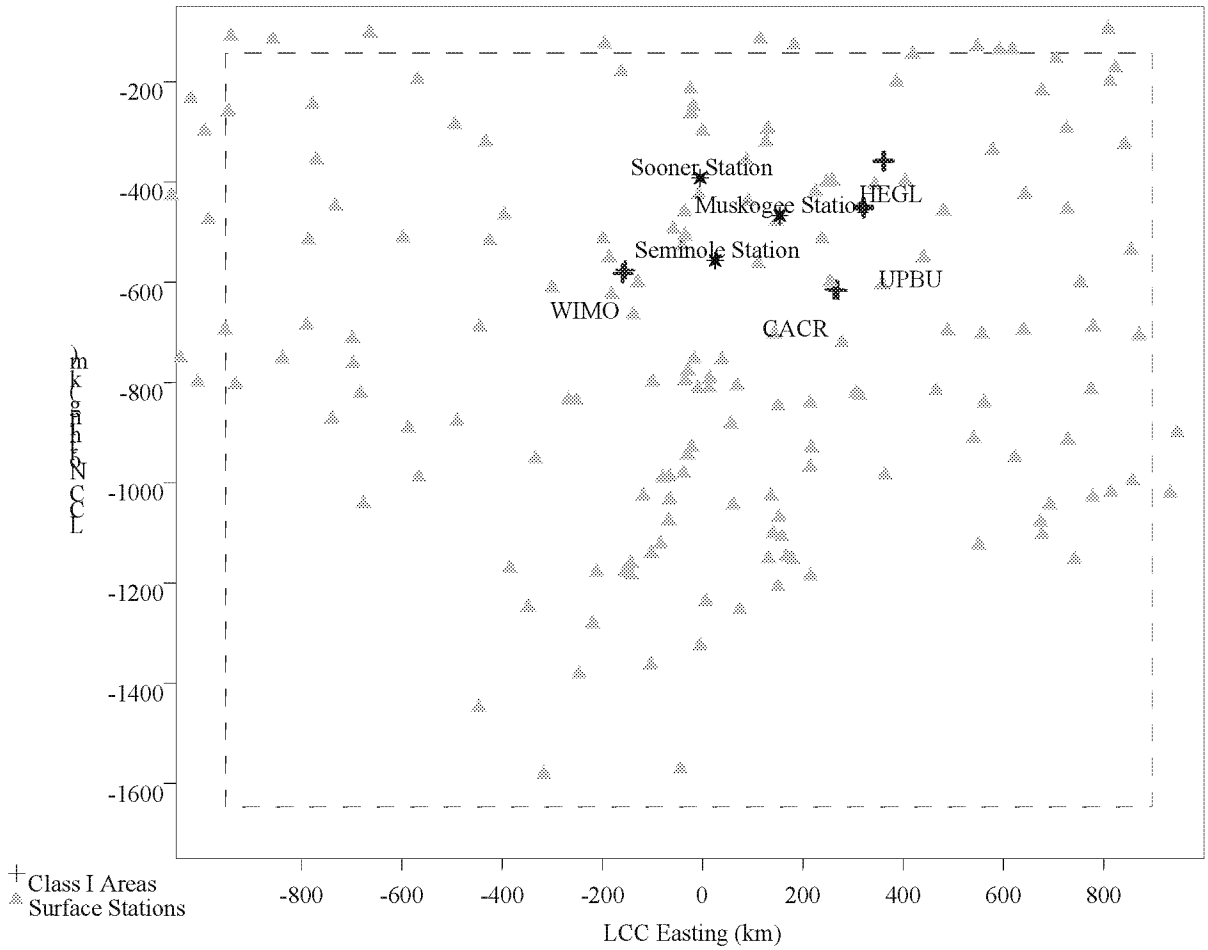
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

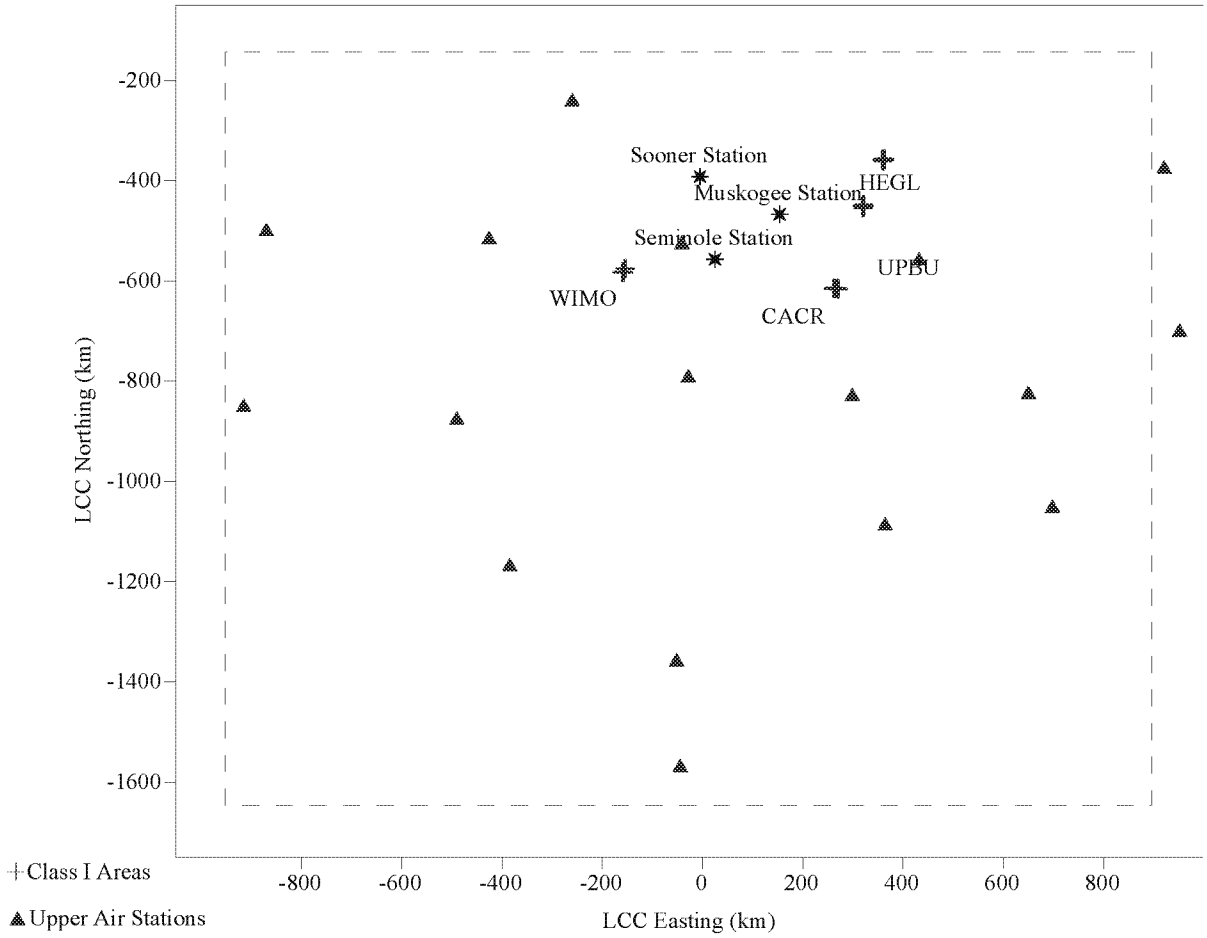
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

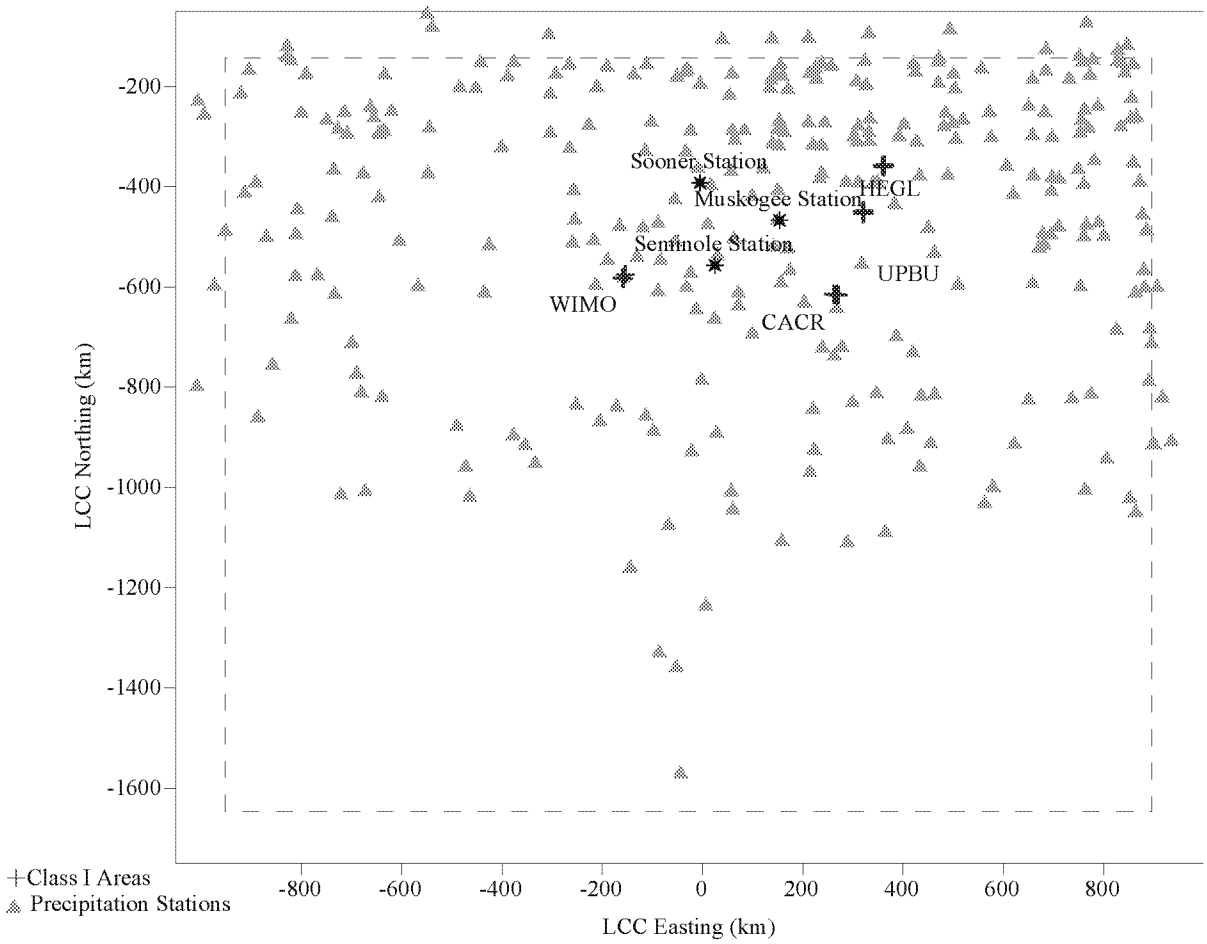
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

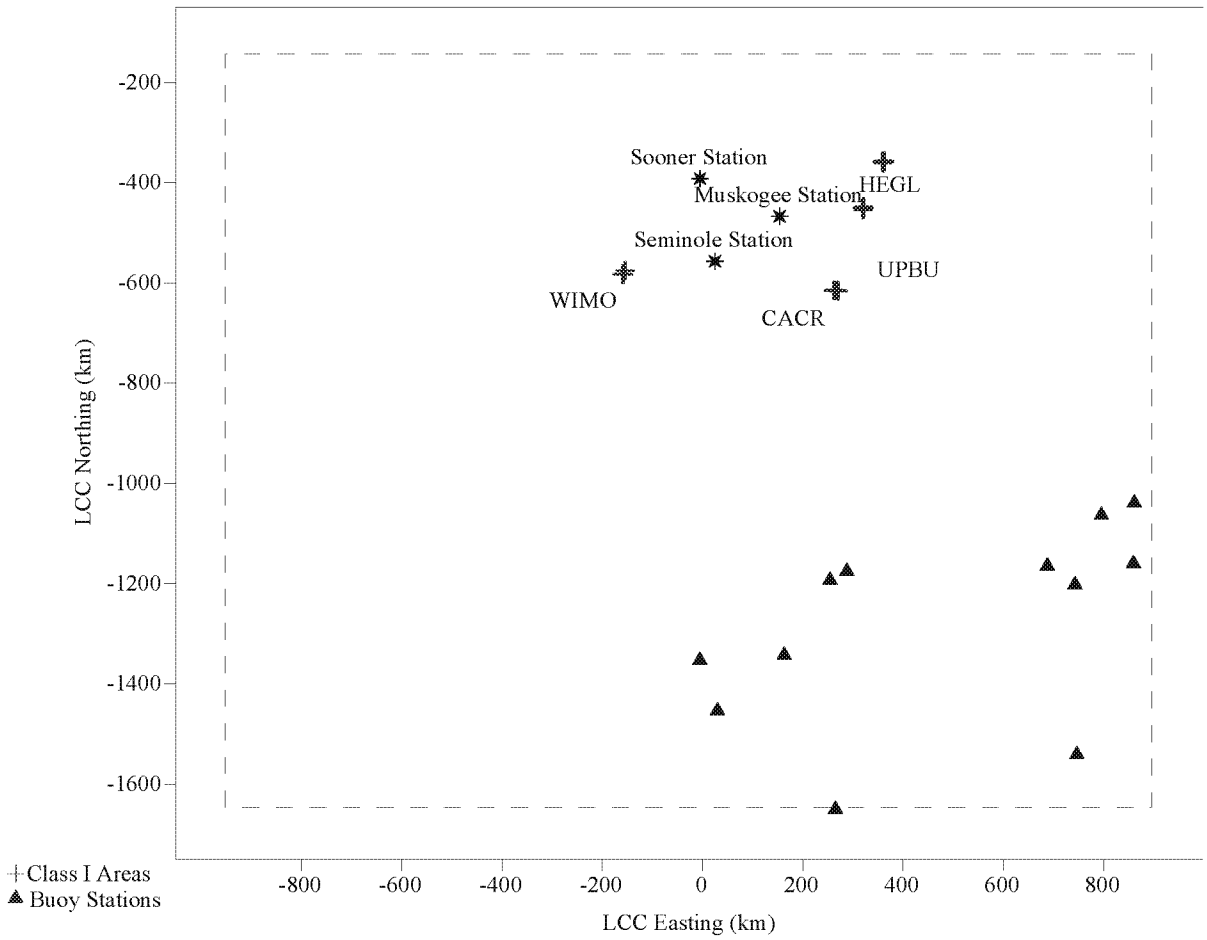
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

APPENDIX D

CEMS DATA FROM CAMD FOR 2001 TO 2003 AND 2009 TO 2011

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
1	1/5/2001	1.427	26,054
1	1/6/2001	42.883	149,330
1	1/7/2001	68.245	194,455
1	1/8/2001	63.914	182,770
1	1/9/2001	67.859	204,772
1	1/10/2001	65.955	190,485
1	1/11/2001	70.031	202,920
1	1/12/2001	56.743	187,273
1	1/13/2001	64.013	207,805
1	1/14/2001	48.542	144,623
1	1/15/2001	67.075	192,264
1	1/16/2001	57.886	185,487
1	1/17/2001	68.777	198,849
1	1/18/2001	62.858	188,091
1	1/19/2001	58.119	185,976
1	1/20/2001	66.6	191,109
1	1/21/2001	69.856	206,742
1	1/22/2001	65.144	190,490
1	1/23/2001	64.994	194,193
1	1/24/2001	56.804	182,694
1	1/25/2001	63.27	202,127
1	1/26/2001	55.296	171,617
1	4/3/2001	0.547	6,873
1	4/4/2001	1.055	8,573
1	4/5/2001	1.546	10,088
1	4/6/2001	8.967	38,007
1	4/7/2001	6.478	26,784
1	4/9/2001	5.976	26,103
1	4/10/2001	24.207	93,161
1	4/11/2001	55.76	174,874
1	4/12/2001	59.522	173,490
1	4/13/2001	54.427	165,840
1	4/14/2001	58.422	171,216
1	4/15/2001	24.188	72,680
1	4/16/2001	2.533	10,525
1	4/17/2001	56.651	164,701
1	4/18/2001	64.409	164,695
1	4/19/2001	61.953	160,949
1	4/20/2001	63.59	173,481
1	4/21/2001	31.694	94,929
1	4/22/2001	59.626	164,679
1	4/23/2001	43.525	120,867
1	4/24/2001	9.105	28,862
1	4/25/2001	62.678	180,855
1	4/26/2001	49.349	140,127

1	4/27/2001	62.261	187,109
1	4/28/2001	62.59	179,852
1	4/29/2001	52.9	155,338
1	4/30/2001	69.128	180,489
1	5/1/2001	49.114	136,478
1	5/2/2001	63.29	182,498
1	5/3/2001	62.078	184,546
1	5/4/2001	63.607	185,637
1	5/5/2001	60.206	174,287
1	5/6/2001	55.887	164,969
1	5/7/2001	66.414	181,665
1	5/8/2001	66.104	187,835
1	5/9/2001	61.648	183,461
1	5/10/2001	61.171	181,272
1	5/11/2001	57.942	172,097
1	5/12/2001	5.656	17,561
1	5/13/2001	0.609	3,950
1	5/14/2001	55.397	159,810
1	5/15/2001	64.475	183,212
1	5/16/2001	63.77	181,857
1	5/17/2001	59.676	176,776
1	5/18/2001	61.378	176,568
1	5/19/2001	64.114	180,838
1	5/20/2001	59.087	170,626
1	5/21/2001	50.906	148,628
1	5/22/2001	52.519	154,556
1	5/23/2001	58.172	170,287
1	5/24/2001	61.455	179,175
1	5/25/2001	58.992	169,017
1	5/26/2001	60.789	175,004
1	5/27/2001	58.749	172,696
1	5/28/2001	64.869	174,922
1	5/29/2001	60.546	180,550
1	5/30/2001	59.685	173,119
1	5/31/2001	55.194	161,952
1	6/1/2001	56.076	161,968
1	6/2/2001	62.356	179,767
1	6/3/2001	62.691	187,445
1	6/4/2001	69.826	195,288
1	6/5/2001	65.276	187,650
1	6/6/2001	62.966	184,410
1	6/7/2001	62.048	178,041
1	6/8/2001	70.887	192,530
1	6/9/2001	59.876	178,409
1	6/10/2001	58.98	177,831
1	6/11/2001	61.296	185,722
1	6/12/2001	68.818	196,712

1	6/13/2001	72.77	206,791
1	6/14/2001	82.035	228,623
1	6/15/2001	72.149	202,380
1	6/16/2001	69.886	199,793
1	6/17/2001	71.396	201,210
1	6/18/2001	75.678	217,184
1	6/19/2001	69.793	203,565
1	6/20/2001	70.83	204,866
1	6/21/2001	69.739	203,174
1	6/22/2001	69.941	208,054
1	6/23/2001	67.056	193,075
1	6/24/2001	66.104	193,681
1	6/25/2001	62.686	186,522
1	6/26/2001	68.046	197,197
1	6/27/2001	59.758	173,545
1	6/28/2001	69.789	201,036
1	6/29/2001	71.015	199,606
1	6/30/2001	67.63	196,607
1	7/1/2001	64.938	190,313
1	7/2/2001	67.968	201,234
1	7/3/2001	74.092	198,062
1	7/4/2001	68.436	197,642
1	7/5/2001	67.987	196,138
1	7/6/2001	65.934	200,553
1	7/7/2001	67.562	194,432
1	7/8/2001	61.583	219,889
1	7/9/2001	59.883	204,470
1	7/10/2001	83.794	215,984
1	7/11/2001	67.369	194,599
1	7/12/2001	64.477	189,174
1	7/13/2001	7.831	34,051
1	7/14/2001	68.11	194,471
1	7/15/2001	69.282	181,728
1	7/16/2001	70.182	195,428
1	7/17/2001	56.916	200,084
1	7/18/2001	67.033	211,803
1	7/19/2001	67.091	201,315
1	7/20/2001	79.587	213,335
1	7/21/2001	67.74	202,185
1	7/22/2001	70.121	207,400
1	7/23/2001	58.683	178,725
1	7/24/2001	57.098	206,917
1	7/25/2001	52.214	177,632
1	7/26/2001	70.82	217,541
1	7/27/2001	68.711	199,604
1	7/28/2001	69.585	206,823
1	7/29/2001	49.378	192,050

1	7/30/2001	54.797	208,774
1	7/31/2001	69.394	201,992
1	8/1/2001	63.745	189,763
1	8/2/2001	71.075	218,726
1	8/3/2001	69.396	200,818
1	8/4/2001	64.49	197,670
1	8/5/2001	64.868	191,622
1	8/6/2001	63.636	212,620
1	8/7/2001	57.665	191,653
1	8/8/2001	64.678	213,642
1	8/9/2001	47.023	193,280
1	8/10/2001	58.4	208,250
1	8/11/2001	48.012	184,435
1	8/12/2001	60.14	189,596
1	8/13/2001	57.645	181,656
1	8/14/2001	58.304	186,898
1	8/15/2001	58.225	180,890
1	8/16/2001	71.981	214,532
1	8/17/2001	64.94	198,444
1	8/18/2001	67.218	203,643
1	8/19/2001	67.619	192,562
1	8/20/2001	65.533	194,140
1	8/21/2001	62.648	196,979
1	8/22/2001	68.512	199,137
1	8/23/2001	70.948	209,984
1	8/24/2001	63.321	194,695
1	8/25/2001	59.971	192,155
1	8/26/2001	62.562	189,841
1	8/27/2001	67.055	195,409
1	8/28/2001	63.287	190,177
1	8/29/2001	69.2	199,246
1	8/30/2001	61.391	189,474
1	8/31/2001	65.847	203,921
1	9/1/2001	60.489	185,501
1	9/2/2001	57.116	170,413
1	9/3/2001	55.47	188,460
1	9/4/2001	52.537	205,793
1	9/5/2001	69.889	198,384
1	9/6/2001	68.654	207,117
1	9/7/2001	62.387	187,751
1	9/8/2001	69.789	198,880
1	9/9/2001	58.532	171,631
1	9/10/2001	51.286	186,885
1	9/11/2001	58.135	183,969
1	9/12/2001	64.083	193,770
1	9/13/2001	66.92	207,704
1	9/14/2001	65.662	199,431

1	9/15/2001	47.991	149,423
1	9/16/2001	61.057	173,907
1	9/17/2001	64.579	196,262
1	9/18/2001	66.304	197,588
1	9/19/2001	42.479	135,150
1	9/20/2001	59.628	188,047
1	9/21/2001	55.154	191,343
1	9/22/2001	59.266	203,172
1	9/23/2001	52.687	178,601
1	9/24/2001	61.1	191,425
1	9/25/2001	58.935	173,197
1	9/26/2001	58.448	172,509
1	9/27/2001	64.197	190,973
1	9/28/2001	59.903	183,833
1	9/29/2001	52.612	164,330
1	9/30/2001	47.5	151,261
1	10/1/2001	55.079	172,521
1	10/2/2001	48.89	185,647
1	10/3/2001	55.909	193,065
1	10/4/2001	61.833	206,607
1	10/8/2001	36.186	112,976
1	10/9/2001	72.988	220,068
1	10/10/2001	66.767	206,153
1	10/11/2001	66.98	219,629
1	10/12/2001	59.135	188,092
1	10/13/2001	62.573	194,097
1	10/14/2001	51.93	161,238
1	10/15/2001	61.904	193,931
1	10/16/2001	62.534	190,118
1	10/17/2001	62.392	191,378
1	10/18/2001	55.951	175,127
1	10/19/2001	43.663	140,910
1	10/21/2001	0.262	8,330
1	10/22/2001	35.667	126,447
1	10/23/2001	25.149	78,862
1	10/24/2001	12.77	50,607
1	10/25/2001	66.722	207,816
1	10/26/2001	62.93	193,711
1	10/27/2001	59.814	193,744
1	10/28/2001	67.952	212,723
1	10/29/2001	62.573	196,544
1	10/30/2001	68.954	213,301
1	10/31/2001	61.194	189,622
1	11/1/2001	63.85	199,791
1	11/2/2001	62.444	192,209
1	11/3/2001	67.009	174,125
1	11/4/2001	54.729	170,634

1	11/5/2001	63.401	199,959
1	11/6/2001	66.746	205,470
1	11/7/2001	49.409	157,872
1	11/8/2001	69.802	213,781
1	11/9/2001	64.883	203,484
1	11/10/2001	73.337	218,963
1	11/11/2001	61.848	187,807
1	11/12/2001	65.828	204,133
1	11/13/2001	63.046	189,526
1	11/14/2001	22.495	92,696
1	11/15/2001	36.48	111,862
1	11/16/2001	36.041	114,142
1	11/17/2001	35.271	115,121
1	11/18/2001	32.37	105,190
1	11/21/2001	0.361	9,218
1	11/22/2001	28.09	104,413
1	11/23/2001	45.663	142,873
1	11/24/2001	48.864	149,650
1	11/25/2001	47.17	157,334
1	11/26/2001	60.874	188,092
1	11/27/2001	66.46	203,520
1	11/28/2001	63.65	198,498
1	11/29/2001	71.885	218,758
1	11/30/2001	66.244	185,155
1	12/1/2001	64.506	193,567
1	12/2/2001	45.619	139,533
1	12/3/2001	59.412	195,898
1	12/4/2001	67.238	203,423
1	12/5/2001	65.347	196,961
1	12/6/2001	66.744	199,382
1	12/7/2001	65.415	190,727
1	12/8/2001	58.997	188,729
1	12/9/2001	57.892	180,602
1	12/10/2001	71.695	204,009
1	12/11/2001	71.263	198,053
1	12/12/2001	65.161	194,984
1	12/13/2001	64.638	191,787
1	12/14/2001	62.025	189,609
1	12/15/2001	55.166	191,899
1	12/16/2001	60.591	193,126
1	12/17/2001	58.482	185,205
1	12/18/2001	64.737	197,302
1	12/19/2001	61.156	186,406
1	12/20/2001	68.073	202,192
1	12/21/2001	57.529	181,524
1	12/22/2001	58.981	185,305
1	12/23/2001	51.357	174,111

1	12/24/2001	59.022	184,946
1	12/25/2001	50.786	161,430
1	12/26/2001	66.38	205,423
1	12/27/2001	64.214	194,709
1	12/28/2001	64.287	192,369
1	12/29/2001	61.542	192,964
1	12/30/2001	65.491	212,269
1	12/31/2001	47.421	191,796
1	1/1/2002	63.679	210,165
1	1/2/2002	63.43	201,368
1	1/3/2002	67.6	206,525
1	1/4/2002	65.712	198,917
1	1/5/2002	61.49	190,678
1	1/6/2002	64.831	200,976
1	1/7/2002	62.917	197,310
1	1/8/2002	54.84	171,604
1	1/9/2002	53.326	171,734
1	1/10/2002	63.441	195,374
1	1/11/2002	62.568	188,959
1	1/12/2002	68.436	202,097
1	1/13/2002	63.656	186,189
1	1/14/2002	74.083	201,801
1	1/15/2002	66.62	197,855
1	1/16/2002	73.726	214,133
1	1/17/2002	64.49	192,439
1	1/18/2002	69.301	208,951
1	1/19/2002	25.979	77,912
1	1/21/2002	0.188	3,231
1	1/22/2002	55.559	176,106
1	1/23/2002	62.193	190,325
1	1/24/2002	50.749	160,297
1	1/25/2002	61.775	193,282
1	1/26/2002	61.535	197,676
1	1/27/2002	56.132	180,536
1	1/28/2002	64.414	181,611
1	1/29/2002	64.231	189,953
1	1/30/2002	64.22	198,999
1	1/31/2002	66.106	192,014
1	2/1/2002	69.319	210,093
1	2/2/2002	59.419	178,351
1	2/3/2002	65.519	198,493
1	2/4/2002	65.006	198,991
1	2/5/2002	70.877	210,678
1	2/6/2002	61.769	188,285
1	2/7/2002	67.84	204,820
1	2/8/2002	59.141	180,179
1	2/9/2002	66.066	207,388

1	2/10/2002	59.946	180,151
1	2/11/2002	69.365	209,221
1	2/12/2002	61.579	192,686
1	2/13/2002	67.463	207,532
1	2/14/2002	41.55	154,075
1	2/16/2002	18.353	67,944
1	2/17/2002	64.472	203,175
1	2/18/2002	56.369	184,089
1	2/19/2002	67.73	206,560
1	2/20/2002	59.191	191,606
1	2/21/2002	74.264	224,126
1	2/22/2002	54.91	198,622
1	2/23/2002	52.745	219,630
1	2/24/2002	49.357	179,837
1	2/25/2002	70.098	204,152
1	2/26/2002	53.344	194,187
1	2/27/2002	64.448	206,536
1	2/28/2002	58.543	184,634
1	3/1/2002	68.764	218,362
1	3/2/2002	60.402	190,520
1	3/3/2002	68.446	209,229
1	3/4/2002	62.583	191,590
1	3/5/2002	70.861	214,707
1	3/6/2002	64.212	203,299
1	3/7/2002	70.486	214,514
1	3/8/2002	61.141	186,812
1	4/13/2002	5.708	20,969
1	4/14/2002	34.795	106,854
1	4/15/2002	57.024	166,491
1	4/16/2002	53.047	171,720
1	4/17/2002	53.468	175,834
1	4/18/2002	43.8	166,016
1	4/19/2002	48.83	175,977
1	4/20/2002	8.323	28,418
1	4/21/2002	0.003	580
1	4/22/2002	38.239	113,983
1	4/23/2002	68.634	190,260
1	4/24/2002	63.012	191,729
1	4/25/2002	63.787	197,983
1	4/26/2002	59.158	185,084
1	4/27/2002	69.829	199,244
1	4/28/2002	69.214	186,436
1	4/29/2002	70.324	197,582
1	4/30/2002	65.809	191,490
1	5/1/2002	73.078	189,345
1	5/2/2002	62.135	174,389
1	5/3/2002	65.047	185,059

1	5/4/2002	61.545	174,429
1	5/5/2002	63.546	183,352
1	5/6/2002	61.198	179,430
1	5/7/2002	69.438	188,297
1	5/8/2002	62.149	169,536
1	5/9/2002	66.113	182,139
1	5/10/2002	38.24	144,931
1	5/11/2002	35.014	116,084
1	5/12/2002	54.48	161,097
1	5/13/2002	62.067	170,670
1	5/14/2002	55.953	165,617
1	5/15/2002	67.13	216,015
1	5/16/2002	61.757	191,148
1	5/19/2002	19.888	74,291
1	5/20/2002	58.383	158,571
1	5/21/2002	58.11	160,272
1	5/22/2002	64.735	186,565
1	5/23/2002	58.363	168,141
1	5/24/2002	68	192,062
1	5/25/2002	65.193	184,983
1	5/26/2002	65.7	186,889
1	5/27/2002	68.492	186,964
1	5/28/2002	68.606	180,790
1	5/29/2002	66.227	185,455
1	5/30/2002	68.742	196,710
1	5/31/2002	64.839	187,781
1	6/1/2002	69.158	192,581
1	6/2/2002	65.068	183,215
1	6/3/2002	77.57	200,837
1	6/4/2002	70.507	189,222
1	6/5/2002	78.176	213,694
1	6/6/2002	67.509	192,390
1	6/7/2002	67.76	201,030
1	6/8/2002	65.933	190,291
1	6/9/2002	66.485	191,411
1	6/10/2002	66.865	194,536
1	6/11/2002	71.58	208,004
1	6/12/2002	65.373	188,944
1	6/13/2002	75.211	208,049
1	6/14/2002	60.856	173,253
1	6/15/2002	64.898	184,036
1	6/16/2002	56.896	167,608
1	6/17/2002	63.565	188,633
1	6/18/2002	63.102	186,073
1	6/19/2002	79.317	195,493
1	6/20/2002	79.393	189,472
1	6/21/2002	73.805	197,863

1	6/22/2002	49.797	143,284
1	6/23/2002	75.952	210,428
1	6/24/2002	68.298	191,123
1	6/25/2002	78.177	203,120
1	6/26/2002	71.694	188,443
1	6/27/2002	69.505	183,540
1	6/28/2002	65.062	185,336
1	6/29/2002	68.421	186,719
1	6/30/2002	71.327	193,656
1	7/1/2002	79.947	217,232
1	7/2/2002	70.741	198,667
1	7/3/2002	67.705	216,727
1	7/4/2002	66.951	188,922
1	7/5/2002	64.28	199,855
1	7/6/2002	54.728	192,169
1	7/7/2002	56.335	188,886
1	7/8/2002	59.271	194,915
1	7/9/2002	74.651	209,347
1	7/10/2002	67.581	184,702
1	7/11/2002	68.305	182,884
1	7/12/2002	68.551	187,138
1	7/13/2002	76.388	208,472
1	7/14/2002	70.828	197,928
1	7/15/2002	69.823	211,579
1	7/16/2002	63.73	193,356
1	7/17/2002	67.856	189,957
1	7/18/2002	72.426	186,966
1	7/19/2002	73.675	189,888
1	7/20/2002	69.983	185,830
1	7/21/2002	76.773	205,421
1	7/22/2002	68.664	191,286
1	7/23/2002	72.324	195,212
1	7/24/2002	76.622	210,335
1	7/25/2002	66.019	189,454
1	7/26/2002	79.278	206,613
1	7/27/2002	69.296	195,490
1	7/28/2002	69.506	215,790
1	7/29/2002	63.288	189,536
1	7/30/2002	31.158	89,903
1	7/31/2002	0.119	11,078
1	8/1/2002	52.278	165,075
1	8/2/2002	71.323	205,542
1	8/3/2002	66.838	191,490
1	8/4/2002	75.336	211,226
1	8/5/2002	64.167	182,521
1	8/6/2002	75.767	208,980
1	8/7/2002	69.578	193,962

1	8/8/2002	73.682	199,447
1	8/9/2002	67.065	191,470
1	8/10/2002	65.249	177,073
1	8/11/2002	57.964	156,967
1	8/12/2002	62.398	172,804
1	8/13/2002	68.958	187,693
1	8/14/2002	73.119	205,366
1	8/15/2002	70.911	202,259
1	8/16/2002	61.045	187,020
1	8/17/2002	75.284	205,494
1	8/18/2002	60.227	182,750
1	8/19/2002	70.463	212,434
1	8/20/2002	66.725	195,101
1	8/21/2002	72.13	214,663
1	8/22/2002	66.974	195,545
1	8/23/2002	71.867	216,637
1	8/24/2002	63.142	187,508
1	8/25/2002	70.874	202,602
1	8/26/2002	67.41	189,884
1	8/27/2002	69.688	196,659
1	8/28/2002	63.118	181,584
1	8/29/2002	72.557	207,110
1	8/30/2002	66.942	189,760
1	8/31/2002	75.762	205,778
1	9/1/2002	55.924	185,580
1	9/2/2002	67.586	197,260
1	9/3/2002	70.147	191,949
1	9/4/2002	83.826	203,721
1	9/5/2002	69.924	187,708
1	9/6/2002	73.166	205,867
1	9/7/2002	69.284	188,362
1	9/8/2002	69.52	193,741
1	9/9/2002	62.599	188,709
1	9/10/2002	73.98	210,022
1	9/11/2002	68.141	190,295
1	9/12/2002	66.791	204,978
1	9/13/2002	63.838	182,704
1	9/14/2002	73.45	210,815
1	9/15/2002	63.503	193,497
1	9/16/2002	69.72	214,873
1	9/17/2002	62.437	191,286
1	9/18/2002	73.106	215,255
1	9/19/2002	69.606	200,089
1	9/20/2002	70.428	212,169
1	9/21/2002	63.715	187,640
1	9/22/2002	69.43	197,599
1	9/23/2002	62.004	182,589

1	9/24/2002	64.476	183,324
1	9/25/2002	57.247	162,246
1	9/26/2002	59.154	177,372
1	9/27/2002	62.503	181,676
1	9/28/2002	77.516	198,966
1	9/29/2002	68.433	180,931
1	9/30/2002	71.244	201,058
1	10/1/2002	64.037	177,954
1	10/2/2002	72.814	198,480
1	10/3/2002	68.824	180,764
1	10/4/2002	74.934	200,236
1	10/5/2002	66.208	182,168
1	10/6/2002	65.293	206,104
1	10/7/2002	57.704	184,131
1	10/8/2002	70.366	165,991
1	10/9/2002	68.841	174,546
1	10/10/2002	72.823	205,605
1	10/11/2002	62.789	196,835
1	10/12/2002	67.896	219,518
1	10/13/2002	64.469	192,609
1	10/14/2002	76.585	209,355
1	10/15/2002	61.276	184,644
1	10/16/2002	63.876	190,268
1	10/17/2002	63.739	178,031
1	10/18/2002	71.555	196,906
1	10/19/2002	65.951	179,201
1	10/20/2002	69.229	184,225
1	10/21/2002	67.223	172,452
1	10/22/2002	68.757	200,912
1	10/23/2002	66.493	181,742
1	10/24/2002	77.876	197,936
1	10/25/2002	66.975	188,079
1	10/26/2002	72.399	203,780
1	10/27/2002	23.99	74,983
1	10/28/2002	54.183	149,783
1	10/29/2002	62.737	145,898
1	10/30/2002	50.869	128,978
1	10/31/2002	70.349	186,719
1	11/1/2002	67.923	185,442
1	11/2/2002	59.053	158,260
1	11/3/2002	63.912	177,005
1	11/4/2002	67.24	179,065
1	11/5/2002	74.584	200,208
1	11/6/2002	59.928	179,634
1	11/7/2002	72.689	196,407
1	11/8/2002	67.716	178,329
1	11/9/2002	77.283	191,726

1	11/10/2002	63.848	171,424
1	11/11/2002	72.94	193,090
1	11/12/2002	61.283	167,255
1	11/13/2002	69.047	188,017
1	11/14/2002	65.669	178,330
1	11/15/2002	73.693	194,656
1	11/16/2002	66.131	172,077
1	11/17/2002	69.205	194,371
1	11/18/2002	63.507	172,577
1	11/19/2002	71.279	187,306
1	11/20/2002	57.233	149,545
1	11/22/2002	0.285	2,467
1	11/23/2002	43.397	119,570
1	11/24/2002	70.071	193,889
1	11/25/2002	65.963	178,921
1	11/26/2002	65.652	192,450
1	11/27/2002	70.457	162,879
1	11/28/2002	64.064	161,891
1	11/29/2002	46.986	123,508
1	11/30/2002	64.959	169,536
1	12/1/2002	66.605	169,543
1	12/2/2002	73.74	192,490
1	12/3/2002	70.465	178,915
1	12/4/2002	76.84	197,882
1	12/5/2002	66.449	167,574
1	12/6/2002	72.172	176,674
1	12/7/2002	62.203	168,865
1	12/8/2002	65.528	190,748
1	12/9/2002	61.204	179,392
1	12/10/2002	73.699	186,035
1	12/11/2002	67.461	170,849
1	12/12/2002	75.376	194,554
1	12/13/2002	59.989	153,460
1	12/14/2002	68.99	177,279
1	12/15/2002	68.305	160,456
1	12/16/2002	76.191	180,966
1	12/17/2002	73.332	173,618
1	12/18/2002	76.888	195,180
1	12/19/2002	71.893	176,889
1	12/20/2002	67.569	170,932
1	12/21/2002	62.678	166,491
1	12/22/2002	70.113	179,450
1	12/23/2002	71.766	183,176
1	12/24/2002	70.094	183,058
1	12/25/2002	68.993	179,073
1	12/26/2002	72.084	190,734
1	12/27/2002	66.248	171,995

1	12/28/2002	71.41	188,655
1	12/29/2002	60.327	170,084
1	12/30/2002	60.528	169,080
1	12/31/2002	54.642	149,739
1	1/1/2003	73.915	190,490
1	1/2/2003	78.753	194,372
1	1/3/2003	64.163	174,996
1	1/4/2003	74.148	202,634
1	1/5/2003	66.118	176,220
1	1/6/2003	73.507	201,538
1	1/7/2003	61.691	170,119
1	1/8/2003	53.155	190,141
1	1/9/2003	51.59	150,755
1	1/10/2003	54.815	148,813
1	1/11/2003	67.307	178,120
1	1/12/2003	79.089	196,635
1	1/13/2003	60.962	167,295
1	1/14/2003	63.486	199,432
1	1/15/2003	57.585	174,044
1	1/16/2003	62.495	194,099
1	1/17/2003	31.403	95,315
1	1/18/2003	65.728	183,717
1	1/19/2003	60.339	163,905
1	1/20/2003	61.16	165,939
1	1/21/2003	55.715	164,810
1	1/22/2003	59.21	182,170
1	1/23/2003	55.487	186,596
1	1/24/2003	62.545	198,856
1	1/25/2003	62.512	178,918
1	1/26/2003	66.7	191,266
1	1/27/2003	61.967	169,600
1	1/28/2003	67.579	195,026
1	1/29/2003	61.284	173,870
1	1/30/2003	61.872	198,309
1	1/31/2003	58.385	171,516
1	2/1/2003	75.945	197,489
1	2/2/2003	66.362	168,728
1	2/3/2003	65.998	184,364
1	2/4/2003	68.644	176,414
1	2/5/2003	90.467	196,322
1	2/6/2003	58.866	171,981
1	2/7/2003	78.827	199,612
1	2/8/2003	63.091	174,303
1	2/9/2003	63.7	187,172
1	2/10/2003	48.019	168,271
1	2/11/2003	55.823	169,313
1	2/12/2003	62.516	159,288

1	2/13/2003	61.421	174,121
1	2/14/2003	62.005	158,766
1	2/15/2003	78.969	200,801
1	2/16/2003	72.08	184,036
1	2/17/2003	69.689	202,163
1	2/18/2003	62.206	163,617
1	2/19/2003	68.896	180,477
1	2/20/2003	64.623	173,881
1	2/21/2003	67.163	183,845
1	2/22/2003	57.606	157,110
1	2/23/2003	69.672	192,959
1	2/24/2003	57.34	194,459
1	2/25/2003	55.535	183,066
1	2/26/2003	62.888	185,446
1	2/27/2003	47.595	156,992
1	2/28/2003	51.073	147,424
1	3/1/2003	40.516	108,627
1	3/2/2003	52.253	144,424
1	3/3/2003	48.089	173,987
1	3/4/2003	49.411	152,776
1	3/5/2003	48.333	158,937
1	3/6/2003	58.036	202,330
1	3/7/2003	46.863	145,062
1	3/8/2003	49.793	175,267
1	3/9/2003	70.656	170,559
1	3/10/2003	62.434	202,802
1	3/11/2003	57.399	184,481
1	3/12/2003	45.609	164,665
1	3/13/2003	37.658	145,800
1	3/14/2003	58.95	199,236
1	3/15/2003	61.202	187,834
1	3/16/2003	53.613	170,221
1	3/17/2003	59.39	175,018
1	3/18/2003	78.889	209,616
1	3/19/2003	71.377	186,412
1	3/20/2003	86.469	198,170
1	3/21/2003	75.59	185,082
1	3/22/2003	91.133	212,229
1	3/23/2003	89.95	183,040
1	3/24/2003	68.44	199,438
1	3/25/2003	66.328	167,699
1	3/26/2003	87.734	208,448
1	3/27/2003	62.384	171,469
1	4/1/2003	77.815	192,159
1	4/2/2003	75.176	180,236
1	4/3/2003	66.211	194,903
1	4/4/2003	36.75	175,240

1	4/5/2003	62.096	198,466
1	4/6/2003	68.474	174,682
1	4/7/2003	71.167	204,526
1	4/8/2003	73.012	203,697
1	4/9/2003	76.151	202,733
1	4/10/2003	68.052	175,982
1	4/11/2003	75.146	191,851
1	4/12/2003	70.72	186,941
1	4/13/2003	58.355	150,660
1	4/14/2003	69.968	192,204
1	4/15/2003	57.581	162,914
1	4/16/2003	68.308	187,283
1	4/17/2003	69.638	194,059
1	4/18/2003	47.058	137,341
1	4/19/2003	40.801	138,266
1	4/20/2003	69.525	184,518
1	4/21/2003	63.383	195,627
1	4/22/2003	46.951	156,554
1	4/23/2003	53.949	166,751
1	4/24/2003	57.137	173,637
1	4/25/2003	67.083	198,800
1	4/26/2003	65.889	178,524
1	4/27/2003	63.961	184,933
1	4/28/2003	56.091	164,029
1	5/14/2003	0.049	15,011
1	5/15/2003	15.377	77,551
1	5/16/2003	68.357	191,499
1	5/17/2003	64.285	195,408
1	5/18/2003	18.734	103,256
1	5/19/2003	31.395	95,092
1	5/20/2003	22.936	92,627
1	5/21/2003	28.402	89,420
1	5/22/2003	41.112	124,468
1	5/23/2003	59.486	174,644
1	5/24/2003	54.912	160,872
1	5/25/2003	56.33	165,561
1	5/26/2003	58.981	169,606
1	5/27/2003	63.996	182,690
1	5/28/2003	63.645	171,811
1	5/29/2003	60.784	184,084
1	5/30/2003	54.991	184,091
1	5/31/2003	75.624	209,565
1	6/1/2003	60.852	182,601
1	6/2/2003	63.49	206,040
1	6/3/2003	60.287	183,880
1	6/4/2003	67.308	202,062
1	6/5/2003	60.479	181,552

1	6/6/2003	55.256	192,138
1	6/7/2003	60.258	186,045
1	6/8/2003	65.11	194,271
1	6/9/2003	57.75	176,036
1	6/10/2003	62.436	203,259
1	6/11/2003	66.898	189,842
1	6/12/2003	70.574	207,990
1	6/13/2003	56.696	175,684
1	6/14/2003	71.951	215,265
1	6/15/2003	58.017	186,958
1	6/16/2003	59.332	195,251
1	6/17/2003	50.246	162,323
1	6/18/2003	72.322	208,449
1	6/19/2003	64.908	188,054
1	6/20/2003	67.928	206,650
1	6/21/2003	62.11	190,843
1	6/22/2003	66.638	201,823
1	6/23/2003	64.963	195,499
1	6/24/2003	68.687	206,961
1	6/25/2003	60.499	189,095
1	6/26/2003	72.145	210,390
1	6/27/2003	64.627	187,355
1	6/28/2003	67.706	208,435
1	6/29/2003	67.217	187,558
1	6/30/2003	65.28	203,057
1	7/1/2003	65.351	190,432
1	7/2/2003	69.546	199,595
1	7/3/2003	64.51	190,141
1	7/4/2003	69.444	199,252
1	7/5/2003	63.391	186,550
1	7/6/2003	68.122	194,179
1	7/7/2003	64.627	194,081
1	7/8/2003	70.035	216,937
1	7/9/2003	67.854	192,724
1	7/10/2003	75.468	212,229
1	7/11/2003	40.227	119,467
1	7/12/2003	43.857	177,807
1	7/13/2003	64.739	190,585
1	7/14/2003	75.933	214,321
1	7/15/2003	65.332	189,958
1	7/16/2003	79.905	210,593
1	7/17/2003	66.713	185,541
1	7/18/2003	74.769	200,491
1	7/19/2003	63.41	179,781
1	7/20/2003	64.059	187,000
1	7/21/2003	64.143	182,203
1	7/22/2003	69.373	208,488

1	7/23/2003	61.926	187,284
1	7/24/2003	65.816	188,519
1	7/25/2003	68.838	192,488
1	7/26/2003	75.838	208,652
1	7/27/2003	81.805	189,342
1	7/28/2003	77.288	202,758
1	7/29/2003	64.397	181,305
1	7/30/2003	74.549	207,311
1	7/31/2003	60.462	178,377
1	8/1/2003	79.776	207,621
1	8/2/2003	74.712	190,328
1	8/3/2003	73.136	185,354
1	8/4/2003	69.243	182,655
1	8/5/2003	74.251	202,146
1	8/6/2003	68.204	180,048
1	8/7/2003	81.741	211,571
1	8/8/2003	75.561	180,633
1	8/9/2003	86.654	208,892
1	8/10/2003	72.31	183,393
1	8/11/2003	74.953	181,523
1	8/12/2003	69.09	171,808
1	8/13/2003	86.837	203,211
1	8/14/2003	73.976	186,090
1	8/15/2003	73.209	203,578
1	8/16/2003	67.895	181,561
1	8/17/2003	93.162	196,475
1	8/18/2003	72.154	174,771
1	8/19/2003	74.077	193,269
1	8/20/2003	73.109	175,428
1	8/21/2003	77.381	201,428
1	8/22/2003	70.2	182,433
1	8/23/2003	91.532	202,832
1	8/24/2003	65.128	177,111
1	8/25/2003	73.702	201,739
1	8/26/2003	84.332	190,904
1	8/27/2003	79.137	210,683
1	8/28/2003	78.61	181,626
1	8/29/2003	86.346	205,609
1	8/30/2003	68.113	169,092
1	8/31/2003	60.59	164,527
1	9/1/2003	80.553	183,088
1	9/2/2003	66.713	192,087
1	9/3/2003	84.924	200,176
1	9/4/2003	82.67	203,396
1	9/5/2003	64.663	170,245
1	9/6/2003	71.003	180,289
1	9/7/2003	68.442	188,070

1	9/8/2003	72.396	200,412
1	9/9/2003	52.094	186,675
1	9/10/2003	51.619	204,556
1	9/11/2003	60.897	188,556
1	9/12/2003	77.23	215,322
1	9/13/2003	70.109	191,303
1	9/14/2003	67.612	198,122
1	9/15/2003	50.225	144,245
1	9/16/2003	61.598	186,390
1	9/17/2003	47.096	176,742
1	9/18/2003	73.404	201,265
1	9/19/2003	78.07	183,382
1	9/20/2003	67.711	190,857
1	9/21/2003	50.187	147,848
1	9/22/2003	72.89	209,098
1	9/23/2003	63.921	188,354
1	9/24/2003	72.307	209,389
1	9/25/2003	68.655	189,550
1	9/26/2003	74.139	217,294
1	9/27/2003	62.645	192,418
1	9/28/2003	65.072	196,056
1	9/29/2003	51.733	150,167
1	9/30/2003	75.945	179,170
1	10/1/2003	75.132	191,347
1	10/2/2003	77.766	193,514
1	10/3/2003	70.78	180,580
1	10/4/2003	77.717	197,639
1	10/5/2003	63.532	169,279
1	10/6/2003	74.317	196,516
1	10/7/2003	69.527	176,009
1	10/8/2003	46.857	187,470
1	10/9/2003	59.214	164,025
1	10/10/2003	76.928	183,433
1	10/11/2003	61.462	167,840
1	10/12/2003	67.021	157,181
1	10/13/2003	58.332	149,366
1	10/14/2003	54.619	152,338
1	10/15/2003	67.231	162,497
1	10/16/2003	51.32	139,546
1	10/17/2003	25.108	97,924
1	10/18/2003	31.745	97,235
1	10/19/2003	28.424	115,530
1	10/20/2003	71.574	172,790
1	10/21/2003	58.697	161,902
1	10/22/2003	51.816	140,425
1	10/23/2003	45.927	130,821
1	10/24/2003	62.545	161,974

1	10/25/2003	39.379	114,413
1	10/26/2003	44.288	142,423
1	10/27/2003	70.436	193,057
1	10/28/2003	89.193	215,641
1	10/29/2003	73.661	193,136
1	10/30/2003	74.113	208,511
1	10/31/2003	79.092	190,986
1	11/1/2003	83.82	210,706
1	11/2/2003	76.881	193,170
1	11/3/2003	88.042	215,517
1	11/4/2003	73.123	188,981
1	11/5/2003	83.25	215,410
1	11/6/2003	68.31	193,683
1	11/7/2003	78.174	205,225
1	11/8/2003	68.221	184,594
1	11/9/2003	76.211	207,142
1	11/10/2003	74.678	182,625
1	11/11/2003	62.183	147,918
1	11/12/2003	40.936	112,803
1	11/13/2003	59.962	147,031
1	11/14/2003	69.853	179,370
1	11/15/2003	58.64	199,238
1	11/16/2003	65.906	217,826
1	11/17/2003	66.262	198,597
1	11/18/2003	67.264	209,841
1	11/19/2003	66.151	196,649
1	11/20/2003	1.077	3,432
1	11/23/2003	25.616	89,769
1	11/24/2003	83.178	210,402
1	11/25/2003	47.086	130,602
1	11/26/2003	71.232	211,313
1	11/27/2003	70.576	186,143
1	11/28/2003	81.882	205,139
1	11/29/2003	57.244	183,532
1	11/30/2003	59.679	201,943
1	12/1/2003	58.438	186,624
1	12/2/2003	70.331	210,820
1	12/3/2003	28.762	118,238
1	12/7/2003	6.674	27,268
1	12/8/2003	67.963	191,589
1	12/9/2003	58.688	192,922
1	12/10/2003	71.468	201,157
1	12/11/2003	68.585	188,687
1	12/12/2003	65.425	196,780
1	12/13/2003	67.233	188,328
1	12/14/2003	79.576	195,868
1	12/15/2003	58.623	162,122

1	12/16/2003	60.004	170,922
1	12/17/2003	75.008	205,815
1	12/18/2003	73.319	179,105
1	12/19/2003	78.713	207,009
1	12/20/2003	42.448	140,551
1	12/21/2003	42.35	150,557
1	12/22/2003	69.795	203,348
1	12/23/2003	47.569	192,196
1	12/24/2003	45.567	177,562
1	12/25/2003	53.871	201,360
1	12/26/2003	49.882	194,279
1	12/27/2003	42.371	205,291
1	12/28/2003	38.072	181,144
1	12/29/2003	44.555	203,197
1	12/30/2003	38.917	189,748
1	12/31/2003	40.608	202,584
	Max (tpd) -->	**93.162**	
	Max (lb/hr) -->	**7763.5**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
2	1/10/2001	0.754	33,637
2	1/11/2001	48.572	155,023
2	1/12/2001	69.767	223,001
2	1/13/2001	63.279	199,585
2	1/14/2001	70.944	196,874
2	1/15/2001	70.445	196,066
2	1/16/2001	71.084	214,936
2	1/17/2001	73.798	206,033
2	1/18/2001	80.818	228,270
2	1/19/2001	65.111	199,193
2	1/20/2001	82.298	228,161
2	1/21/2001	67.036	191,946
2	1/22/2001	82.267	231,789
2	1/23/2001	69.272	202,867
2	1/24/2001	67.477	203,133
2	1/25/2001	65.347	208,993
2	1/26/2001	72.167	221,736
2	1/27/2001	62.866	198,308
2	1/28/2001	64.123	208,264
2	1/29/2001	57.277	185,626
2	1/30/2001	71.366	213,747
2	1/31/2001	64.4	192,322
2	2/1/2001	74.805	220,513
2	2/2/2001	65.668	199,773
2	2/3/2001	76.063	219,848
2	2/4/2001	66.935	184,402
2	2/5/2001	73.809	217,446
2	2/6/2001	60.475	165,070
2	2/7/2001	59.292	172,471
2	2/8/2001	58.984	185,584
2	2/9/2001	51.92	154,356
2	2/10/2001	77.024	216,492
2	2/11/2001	59.475	187,862
2	2/12/2001	67.554	213,302
2	2/13/2001	59.31	183,263
2	2/14/2001	73.915	216,849
2	2/15/2001	56.155	185,480
2	2/16/2001	60.275	200,034
2	2/17/2001	60.896	185,447
2	2/18/2001	68.563	210,910
2	2/19/2001	63.536	192,921
2	2/20/2001	67.91	198,402
2	2/21/2001	65.391	193,429
2	2/22/2001	75.288	224,203
2	2/23/2001	66.278	200,474

2	2/24/2001	58.537	179,453
2	2/25/2001	59.957	181,189
2	2/26/2001	67.115	195,041
2	2/27/2001	60.745	174,238
2	2/28/2001	65.639	197,401
2	3/1/2001	62.668	184,455
2	3/2/2001	68.041	191,218
2	3/3/2001	57.07	171,070
2	3/4/2001	54.392	173,991
2	3/5/2001	65.951	197,817
2	3/6/2001	58.349	193,610
2	3/7/2001	78.118	223,725
2	3/8/2001	66.484	208,325
2	3/9/2001	69.273	191,776
2	3/10/2001	71.556	207,104
2	3/11/2001	56.766	160,681
2	3/12/2001	65.797	189,519
2	3/13/2001	63.754	186,465
2	3/14/2001	66.415	190,865
2	3/15/2001	63.324	185,756
2	3/16/2001	63.264	199,374
2	3/17/2001	60.518	184,595
2	3/18/2001	60.969	197,853
2	3/19/2001	66.76	197,346
2	3/20/2001	72.834	214,610
2	3/21/2001	61.998	188,273
2	3/22/2001	67.614	199,344
2	3/23/2001	60.426	186,547
2	3/24/2001	64.326	199,333
2	3/25/2001	53.746	174,018
2	3/26/2001	64.952	205,578
2	3/27/2001	64.971	193,287
2	3/28/2001	62.664	200,393
2	3/29/2001	59.724	185,695
2	3/30/2001	58.081	178,069
2	3/31/2001	68.646	191,096
2	4/1/2001	65.108	187,792
2	4/2/2001	57.317	202,604
2	4/3/2001	61.401	187,272
2	4/4/2001	58.343	194,899
2	4/5/2001	62.93	184,590
2	4/6/2001	59.78	191,757
2	4/7/2001	56.841	184,682
2	4/8/2001	69.676	190,946
2	4/9/2001	70.81	185,970
2	4/10/2001	54.723	197,849
2	4/11/2001	54.058	166,491

2	5/2/2001	4.915	25,051
2	5/3/2001	51.471	164,389
2	5/4/2001	70.899	214,110
2	5/5/2001	71.413	211,101
2	5/6/2001	63.354	193,817
2	5/7/2001	73.029	205,431
2	5/8/2001	68.396	200,902
2	5/9/2001	70.645	217,872
2	5/10/2001	67.923	208,187
2	5/11/2001	71.207	215,447
2	5/12/2001	62.622	180,366
2	5/13/2001	58.775	182,784
2	5/14/2001	68.965	197,405
2	5/15/2001	74.064	215,433
2	5/16/2001	66.586	197,138
2	5/17/2001	71.711	217,359
2	5/18/2001	70.055	206,643
2	5/19/2001	77.958	226,785
2	5/20/2001	68.772	204,157
2	5/21/2001	76.383	227,471
2	5/22/2001	58.712	177,827
2	5/23/2001	65.708	196,638
2	5/24/2001	63.432	189,095
2	5/25/2001	70.807	206,448
2	5/26/2001	65.271	193,677
2	5/27/2001	64.151	192,107
2	5/28/2001	52.023	150,016
2	5/29/2001	67.867	204,749
2	5/30/2001	67.63	199,560
2	5/31/2001	55.825	168,511
2	6/1/2001	62.407	184,927
2	6/2/2001	66.765	198,276
2	6/3/2001	67.295	208,569
2	6/4/2001	72.126	208,934
2	6/5/2001	73.841	217,607
2	6/6/2001	67.472	203,457
2	6/7/2001	69.52	206,278
2	6/8/2001	72.702	200,918
2	6/9/2001	71.159	210,583
2	6/10/2001	61.293	186,716
2	6/11/2001	65.811	203,227
2	6/12/2001	73.256	216,533
2	6/13/2001	76.688	225,531
2	6/14/2001	73.748	213,698
2	6/15/2001	73.415	210,730
2	6/16/2001	66.115	195,508
2	6/17/2001	69.267	201,585

2	6/18/2001	69.607	203,752
2	6/19/2001	70.868	205,665
2	6/20/2001	69.426	200,905
2	6/21/2001	74.099	214,438
2	6/22/2001	65.397	195,042
2	6/23/2001	71.333	204,508
2	6/24/2001	62.279	184,534
2	6/25/2001	69.734	206,170
2	6/26/2001	66.976	190,843
2	6/27/2001	66.883	201,570
2	6/28/2001	66.285	203,199
2	6/29/2001	72.059	202,362
2	6/30/2001	65.79	190,828
2	7/1/2001	63.437	186,111
2	7/2/2001	65.055	192,992
2	7/3/2001	77.963	205,510
2	7/4/2001	68.741	197,931
2	7/5/2001	68.553	197,585
2	7/6/2001	65.11	198,174
2	7/7/2001	74.56	213,383
2	7/8/2001	57.577	200,508
2	7/9/2001	62.687	223,282
2	7/10/2001	80.286	204,301
2	7/11/2001	80.159	221,400
2	7/12/2001	67.158	198,449
2	7/13/2001	80.201	221,335
2	7/14/2001	64.879	186,691
2	7/15/2001	68.191	179,878
2	7/16/2001	64.455	184,835
2	7/17/2001	47.578	174,526
2	7/18/2001	59.551	194,020
2	7/19/2001	70.542	213,198
2	7/20/2001	78.579	212,660
2	7/21/2001	71.753	217,047
2	7/22/2001	67.675	202,953
2	7/23/2001	68.944	210,570
2	7/24/2001	55.819	209,676
2	7/25/2001	62.294	230,575
2	7/26/2001	65.226	205,030
2	7/27/2001	68.019	202,340
2	7/28/2001	26.181	74,905
2	7/31/2001	15.582	46,223
2	8/1/2001	72.198	213,617
2	8/2/2001	68.602	216,562
2	8/3/2001	75.064	222,019
2	8/4/2001	65.508	206,369
2	8/5/2001	75.123	223,639

2	8/6/2001	60.963	209,754
2	8/7/2001	66.684	227,861
2	8/8/2001	68.328	233,054
2	8/9/2001	53.607	225,908
2	8/10/2001	56.111	212,219
2	8/11/2001	57.198	219,172
2	8/12/2001	62.849	207,576
2	8/13/2001	65.699	210,656
2	8/14/2001	61.753	203,483
2	8/15/2001	62.701	199,017
2	8/16/2001	68.982	213,177
2	8/17/2001	72.722	228,291
2	8/18/2001	66.308	208,089
2	8/19/2001	71.842	211,722
2	8/20/2001	66.222	203,776
2	8/21/2001	41.063	134,558
2	8/22/2001	73.13	219,632
2	8/23/2001	75.166	230,730
2	8/24/2001	69.238	218,750
2	8/25/2001	60.076	199,470
2	8/26/2001	65.824	205,122
2	8/27/2001	67.93	205,057
2	8/28/2001	66.653	207,979
2	8/29/2001	69.296	207,352
2	8/30/2001	71.494	227,618
2	8/31/2001	66.864	214,649
2	9/1/2001	71.312	223,891
2	9/2/2001	54.945	171,070
2	9/3/2001	58.511	203,589
2	9/4/2001	53.648	217,219
2	9/5/2001	77.724	229,361
2	9/6/2001	68.612	213,826
2	9/7/2001	76.503	226,878
2	9/8/2001	71.728	201,547
2	9/9/2001	66.574	193,595
2	9/10/2001	57.558	207,255
2	9/11/2001	72.633	230,033
2	9/12/2001	66.838	201,660
2	9/13/2001	73.934	227,204
2	9/14/2001	66.582	202,911
2	9/15/2001	59.653	186,297
2	9/16/2001	62.589	180,933
2	9/17/2001	66.522	204,906
2	9/18/2001	68.244	205,911
2	9/19/2001	74.626	226,638
2	9/20/2001	62.004	196,958
2	9/21/2001	56.879	205,070

2	9/22/2001	58.812	199,954
2	9/23/2001	58.074	198,779
2	9/24/2001	63.074	198,244
2	9/25/2001	62.399	184,066
2	9/26/2001	63.043	186,581
2	9/27/2001	66.482	200,156
2	9/28/2001	63.309	196,213
2	9/29/2001	62.67	194,975
2	9/30/2001	52.489	167,163
2	10/1/2001	64.268	201,430
2	10/2/2001	54.281	205,445
2	10/3/2001	62.915	218,269
2	10/4/2001	61.427	207,816
2	10/5/2001	69.979	226,059
2	10/6/2001	52.653	224,064
2	10/7/2001	62.748	204,980
2	10/8/2001	67.948	216,413
2	10/9/2001	69.421	215,028
2	10/10/2001	73.355	229,679
2	10/11/2001	62.266	208,230
2	10/12/2001	65.488	212,243
2	10/13/2001	58.759	186,099
2	10/14/2001	52.159	164,770
2	10/15/2001	62.781	199,326
2	10/16/2001	70.195	216,177
2	10/17/2001	64.077	202,867
2	10/18/2001	63.541	201,395
2	10/19/2001	57.453	184,769
2	10/20/2001	62.825	197,439
2	10/21/2001	66.511	204,790
2	10/22/2001	66.245	208,530
2	10/23/2001	67.053	216,718
2	10/24/2001	64.778	205,617
2	10/25/2001	58.75	192,113
2	10/26/2001	54.903	177,526
2	11/17/2001	1.436	32,899
2	11/18/2001	35.186	123,443
2	11/19/2001	49.752	170,295
2	11/20/2001	62.651	200,500
2	11/21/2001	55.149	181,063
2	11/22/2001	36.993	125,983
2	11/23/2001	38.869	125,294
2	11/24/2001	45.988	144,401
2	11/25/2001	43.804	151,134
2	11/26/2001	54.635	176,780
2	11/27/2001	62.528	200,430
2	11/28/2001	70.364	229,371

2	11/29/2001	66.22	213,787
2	11/30/2001	57.485	170,671
2	12/1/2001	63.727	197,244
2	12/2/2001	42.317	133,471
2	12/3/2001	59.164	200,205
2	12/4/2001	64.828	204,270
2	12/5/2001	68.503	212,388
2	12/6/2001	62.011	193,322
2	12/7/2001	75.636	222,251
2	12/8/2001	55.142	197,931
2	12/9/2001	57.054	188,726
2	12/10/2001	67.225	201,196
2	12/11/2001	74.844	226,565
2	12/12/2001	66.64	207,128
2	12/13/2001	67.535	207,164
2	12/14/2001	66.079	209,182
2	12/15/2001	66.339	235,036
2	12/16/2001	58.733	194,882
2	12/17/2001	64.843	211,213
2	12/18/2001	61.79	194,774
2	12/19/2001	64.132	202,373
2	12/20/2001	61.942	193,031
2	12/21/2001	68.826	222,563
2	12/22/2001	58.313	189,778
2	12/23/2001	53.796	190,558
2	12/24/2001	58.919	192,729
2	12/25/2001	52.663	176,095
2	12/26/2001	61.802	201,052
2	12/27/2001	71.321	223,889
2	12/28/2001	61.129	193,331
2	12/29/2001	69.055	224,118
2	12/30/2001	65.647	219,707
2	12/31/2001	52.399	227,640
2	1/1/2002	62.443	216,425
2	1/2/2002	70.702	232,973
2	1/3/2002	75.864	245,312
2	1/4/2002	70.449	221,367
2	1/5/2002	73.951	237,679
2	1/6/2002	63.773	208,778
2	1/7/2002	67.44	226,227
2	1/8/2002	46.998	159,482
2	1/9/2002	62.622	212,629
2	1/10/2002	61.763	204,240
2	1/11/2002	62.735	204,685
2	1/12/2002	58.128	189,070
2	1/13/2002	63.343	205,872
2	1/14/2002	39.41	120,321

2	1/19/2002	1.37	10,837
2	1/20/2002	56.205	195,467
2	1/21/2002	72.29	230,019
2	1/22/2002	57.036	186,395
2	1/23/2002	61.568	197,176
2	1/24/2002	55.53	184,772
2	1/25/2002	58.035	191,601
2	1/26/2002	51.602	174,901
2	1/27/2002	52.553	178,355
2	1/28/2002	50.679	152,352
2	1/29/2002	60.533	187,478
2	1/30/2002	58.67	193,409
2	1/31/2002	63.564	197,722
2	2/1/2002	60.209	195,293
2	2/2/2002	64.681	203,080
2	2/3/2002	54.381	171,970
2	2/4/2002	66.661	210,080
2	2/5/2002	67.477	205,471
2	2/6/2002	70.912	222,089
2	2/7/2002	61.621	194,478
2	2/8/2002	62.479	199,087
2	2/9/2002	55.252	182,193
2	2/10/2002	60.083	189,205
2	2/11/2002	58.505	187,336
2	2/12/2002	61.278	200,113
2	2/13/2002	62.493	200,276
2	2/14/2002	53.959	211,516
2	2/15/2002	51.148	204,465
2	2/16/2002	68.171	218,723
2	2/17/2002	50.575	171,532
2	2/18/2002	59.098	204,245
2	2/19/2002	50.629	166,054
2	2/21/2002	0.026	781
2	2/23/2002	18.532	70,454
2	2/24/2002	52.372	189,719
2	2/25/2002	65.295	201,438
2	2/26/2002	56.154	208,396
2	2/27/2002	72.037	236,746
2	2/28/2002	64.238	208,195
2	3/1/2002	58.331	195,938
2	3/2/2002	63.246	206,102
2	3/3/2002	71.965	224,207
2	3/4/2002	70.551	221,266
2	3/5/2002	64.458	199,553
2	3/6/2002	68.816	222,032
2	3/7/2002	61.224	195,503
2	3/8/2002	67.506	216,459

2	3/9/2002	61.484	196,156
2	3/10/2002	70.586	223,914
2	3/11/2002	62.045	203,806
2	3/12/2002	69.607	228,031
2	3/13/2002	56.569	190,646
2	3/14/2002	56.669	230,970
2	3/15/2002	52.218	180,817
2	4/2/2002	1.005	7,048
2	4/3/2002	30.442	98,839
2	4/4/2002	71.24	213,172
2	4/5/2002	64.366	196,330
2	4/6/2002	70.825	211,075
2	4/7/2002	67.165	203,299
2	4/8/2002	67.72	207,416
2	4/9/2002	64.94	196,108
2	4/10/2002	66.561	211,263
2	4/11/2002	31.135	105,732
2	4/12/2002	66.671	201,828
2	4/13/2002	70.558	215,952
2	4/14/2002	62.103	195,979
2	4/15/2002	69.001	209,466
2	4/16/2002	60.639	205,080
2	4/17/2002	61.127	199,518
2	4/18/2002	54.461	206,262
2	4/19/2002	62.814	211,213
2	4/20/2002	67.041	218,172
2	4/21/2002	63.153	206,199
2	4/22/2002	72.421	225,344
2	4/23/2002	68.627	202,654
2	4/24/2002	69.78	213,992
2	4/25/2002	63.821	199,226
2	4/26/2002	66.662	207,529
2	4/27/2002	67.558	197,847
2	4/28/2002	78.7	217,106
2	4/29/2002	69.386	198,134
2	4/30/2002	68.806	207,862
2	5/1/2002	74.322	199,942
2	5/2/2002	79.624	225,804
2	5/3/2002	63.515	188,412
2	5/4/2002	73.497	212,408
2	5/5/2002	64.424	191,681
2	5/6/2002	70.065	214,917
2	5/7/2002	54.22	166,496
2	5/8/2002	1.497	5,124
2	7/14/2002	0.049	12,297
2	7/15/2002	12.132	63,796
2	7/16/2002	28.317	102,351

2	7/17/2002	33.698	110,894
2	7/18/2002	37.537	113,716
2	7/19/2002	40.27	117,689
2	7/20/2002	38.357	117,244
2	7/21/2002	38.988	118,885
2	7/22/2002	40.61	125,594
2	7/23/2002	42.915	131,892
2	7/24/2002	40.241	123,002
2	7/25/2002	37.361	115,289
2	7/27/2002	0	2,084
2	7/28/2002	26.878	101,064
2	7/29/2002	41.445	132,686
2	7/30/2002	42.387	132,270
2	7/31/2002	38.205	119,888
2	8/1/2002	39.95	129,553
2	8/2/2002	40.337	125,598
2	8/3/2002	42.239	132,488
2	8/4/2002	42.95	133,154
2	8/5/2002	43.385	130,753
2	8/6/2002	40.455	125,782
2	8/7/2002	43.123	129,834
2	8/8/2002	43.569	128,427
2	8/9/2002	43.707	130,776
2	8/10/2002	43.608	122,620
2	8/11/2002	46.613	130,424
2	8/12/2002	45.51	130,658
2	8/13/2002	45.872	130,659
2	8/14/2002	41.298	122,162
2	8/15/2002	42.519	129,385
2	8/16/2002	40.682	131,262
2	8/17/2002	42.923	125,941
2	8/18/2002	35.574	112,584
2	8/19/2002	36.749	117,565
2	8/20/2002	40.825	126,432
2	8/21/2002	42.211	132,139
2	8/22/2002	44.507	133,130
2	8/23/2002	38.883	123,059
2	8/24/2002	43.506	133,585
2	8/25/2002	42.62	129,702
2	8/26/2002	42.974	129,878
2	8/27/2002	40.749	125,442
2	8/28/2002	43.644	132,711
2	8/29/2002	43.262	130,706
2	8/30/2002	42.692	127,650
2	8/31/2002	42.006	122,818
2	9/1/2002	37.586	129,007
2	9/2/2002	42.465	131,335

2	9/3/2002	46.488	133,977
2	9/4/2002	48.912	127,093
2	9/5/2002	48.428	134,055
2	9/6/2002	44.812	133,846
2	9/7/2002	47.637	133,684
2	9/8/2002	43.014	125,865
2	9/9/2002	42.505	134,267
2	9/10/2002	44.97	133,966
2	9/11/2002	46.077	134,731
2	9/12/2002	38.94	127,494
2	9/13/2002	43.019	133,298
2	9/14/2002	43.498	133,266
2	9/15/2002	41.546	133,852
2	9/16/2002	38.665	127,547
2	9/17/2002	40.004	132,831
2	9/18/2002	42.416	133,344
2	9/19/2002	43.755	132,879
2	9/20/2002	39.322	127,258
2	9/21/2002	42.757	132,226
2	9/22/2002	44.43	131,967
2	9/23/2002	43.747	131,537
2	9/24/2002	39.868	119,834
2	9/25/2002	43.73	129,196
2	9/26/2002	40.585	129,194
2	9/27/2002	43.31	132,513
2	9/28/2002	43.877	122,563
2	9/29/2002	46.965	130,039
2	9/30/2002	44.132	133,787
2	10/1/2002	44.799	133,059
2	10/2/2002	43.21	126,877
2	10/3/2002	46.862	131,501
2	10/4/2002	47.388	134,040
2	10/5/2002	46.533	132,296
2	10/6/2002	37.951	129,378
2	10/7/2002	37.966	134,015
2	10/8/2002	52.868	131,411
2	10/9/2002	48.696	130,423
2	10/10/2002	42.076	126,447
2	10/11/2002	43.721	132,825
2	10/12/2002	40.764	133,441
2	10/13/2002	41.794	131,590
2	10/14/2002	43.046	124,950
2	10/15/2002	42.015	131,725
2	10/16/2002	41.245	130,847
2	10/17/2002	42.07	125,099
2	10/18/2002	42.819	125,107
2	10/19/2002	45.384	132,512

2	10/20/2002	41.747	122,107
2	10/21/2002	46.708	127,818
2	10/22/2002	39.902	124,298
2	10/23/2002	46.263	131,562
2	10/24/2002	47.766	131,047
2	10/25/2002	41.849	124,779
2	10/26/2002	41.564	123,656
2	10/27/2002	43.533	129,717
2	10/28/2002	43.741	130,411
2	10/29/2002	51.355	131,682
2	10/30/2002	45.219	125,490
2	10/31/2002	44.394	127,462
2	11/1/2002	44.205	129,628
2	11/2/2002	44.643	129,261
2	11/3/2002	40.96	123,745
2	11/4/2002	44.925	129,527
2	11/5/2002	44.343	129,860
2	11/6/2002	39.085	128,247
2	11/7/2002	39.211	116,214
2	11/8/2002	0.112	713
2	11/9/2002	30.216	89,527
2	11/10/2002	42.778	132,346
2	11/11/2002	45.237	135,241
2	11/12/2002	42.721	133,800
2	11/13/2002	40.472	126,955
2	11/14/2002	43.795	134,896
2	11/15/2002	43.198	131,216
2	11/16/2002	45.042	131,855
2	11/17/2002	38.768	124,964
2	11/18/2002	45.241	134,505
2	11/19/2002	43.17	128,974
2	11/20/2002	44.857	133,926
2	11/21/2002	34.507	124,369
2	11/22/2002	40.563	134,614
2	11/23/2002	41.97	126,004
2	11/24/2002	42.291	130,382
2	11/25/2002	41.495	124,334
2	11/26/2002	37.269	124,510
2	11/27/2002	49.643	130,574
2	11/28/2002	39.346	117,870
2	11/29/2002	36.85	112,104
2	11/30/2002	38.929	116,062
2	12/1/2002	43.494	125,327
2	12/2/2002	43.673	128,968
2	12/3/2002	44.758	128,720
2	12/4/2002	40.619	120,228
2	12/5/2002	44.174	123,841

2	12/6/2002	45.294	122,380
2	12/7/2002	44.022	130,355
2	12/8/2002	39.016	125,323
2	12/9/2002	39.942	128,946
2	12/10/2002	45.545	129,204
2	12/11/2002	46.137	129,573
2	12/12/2002	42.167	122,406
2	12/13/2002	43.991	125,979
2	12/14/2002	42.538	122,758
2	12/15/2002	44.708	118,376
2	12/16/2002	44.316	119,716
2	12/17/2002	50.162	133,839
2	12/18/2002	46.255	134,021
2	12/19/2002	45.517	126,790
2	12/20/2002	40.965	115,263
2	12/21/2002	41.574	121,203
2	12/22/2002	39.851	114,174
2	12/23/2002	46.372	130,222
2	12/24/2002	42.257	121,970
2	12/25/2002	43.695	124,949
2	12/26/2002	45.922	131,297
2	12/27/2002	42.103	126,936
2	12/28/2002	41.979	125,825
2	12/29/2002	41.407	130,355
2	12/30/2002	39.035	125,098
2	12/31/2002	33.961	106,812
2	1/1/2003	0.341	1,291
2	1/2/2003	24.871	75,015
2	1/3/2003	43.488	131,086
2	1/4/2003	44.772	133,140
2	1/5/2003	43.777	127,572
2	1/6/2003	41.851	127,057
2	1/7/2003	43.265	129,584
2	1/8/2003	33.494	135,839
2	1/9/2003	34.51	117,031
2	1/10/2003	32.859	105,555
2	1/11/2003	45.679	133,252
2	1/12/2003	47.269	131,567
2	1/13/2003	43.467	131,756
2	1/14/2003	34.278	121,976
2	1/15/2003	37.056	126,788
2	1/16/2003	35.639	124,641
2	1/17/2003	40.614	126,291
2	1/18/2003	27.459	85,135
2	1/19/2003	17.771	59,166
2	1/20/2003	35.263	109,848
2	1/21/2003	35.953	123,177

2	1/22/2003	37.714	131,248
2	1/23/2003	35.122	129,180
2	1/24/2003	36.233	127,447
2	1/25/2003	39.378	127,484
2	1/26/2003	40.25	132,336
2	1/27/2003	40.483	128,508
2	1/28/2003	37.561	124,953
2	1/29/2003	38.808	128,100
2	1/30/2003	35.494	130,346
2	1/31/2003	38.757	133,533
2	2/1/2003	41.725	127,852
2	2/2/2003	40.329	120,575
2	2/3/2003	42.013	132,787
2	2/4/2003	43.945	124,794
2	2/5/2003	51.338	123,725
2	2/6/2003	41.152	131,622
2	2/7/2003	45.95	131,172
2	2/8/2003	43.205	130,678
2	2/9/2003	36.771	121,808
2	2/10/2003	33.438	126,701
2	2/11/2003	35.582	123,701
2	2/12/2003	47.622	134,658
2	2/13/2003	38.8	124,207
2	2/14/2003	44.771	131,396
2	2/15/2003	46.803	134,435
2	2/16/2003	45.905	132,770
2	2/17/2003	41.288	133,121
2	2/18/2003	45.265	131,622
2	2/19/2003	42.955	126,106
2	2/20/2003	43.088	128,814
2	2/21/2003	38.065	117,061
2	2/22/2003	24.402	77,292
2	2/23/2003	29.682	90,028
2	2/24/2003	40.007	131,088
2	2/25/2003	38.767	126,340
2	2/26/2003	36.996	121,711
2	2/27/2003	35.323	129,456
2	2/28/2003	38.09	123,264
2	3/1/2003	40.001	116,912
2	3/2/2003	40.728	125,999
2	3/3/2003	33.138	132,172
2	3/4/2003	20.669	79,737
2	3/5/2003	36.366	137,002
2	3/6/2003	34.559	126,821
2	3/7/2003	33.253	114,835
2	4/22/2003	0.024	2,455
2	4/23/2003	0.57	6,409

2	4/24/2003	0.346	4,998
2	4/25/2003	1.653	19,701
2	4/26/2003	1.182	11,608
2	4/27/2003	1.331	10,900
2	4/28/2003	27.687	97,392
2	4/29/2003	23.224	72,650
2	5/4/2003	0.227	2,424
2	5/5/2003	17.06	57,849
2	5/6/2003	30.047	78,658
2	5/7/2003	46.492	142,062
2	5/8/2003	72.41	213,935
2	5/9/2003	68.937	207,975
2	5/10/2003	74.992	230,885
2	5/11/2003	67.38	200,812
2	5/12/2003	70.581	210,656
2	5/13/2003	57.171	171,045
2	5/14/2003	70.563	200,534
2	5/15/2003	70.167	202,730
2	5/16/2003	72.346	205,881
2	5/17/2003	58.061	185,961
2	5/18/2003	19.448	115,299
2	5/19/2003	31.077	101,821
2	5/20/2003	22.744	99,360
2	5/21/2003	25.872	89,078
2	5/22/2003	36.635	120,936
2	5/23/2003	48.567	147,872
2	5/24/2003	52.07	156,613
2	5/25/2003	46.489	143,001
2	5/26/2003	58.979	174,641
2	5/27/2003	55.063	161,496
2	5/28/2003	65.86	179,119
2	5/29/2003	55.553	174,322
2	5/30/2003	60.648	208,039
2	5/31/2003	71.727	198,338
2	6/1/2003	70.761	212,833
2	6/2/2003	61.365	203,050
2	6/3/2003	68.958	210,743
2	6/4/2003	62.461	182,842
2	6/5/2003	62.573	183,088
2	6/6/2003	34.208	115,096
2	6/7/2003	65.11	197,511
2	6/8/2003	62.324	181,844
2	6/9/2003	63.884	191,746
2	6/10/2003	63.19	201,659
2	6/11/2003	72.437	206,864
2	6/12/2003	58.341	175,572
2	6/13/2003	56.284	179,098

2	6/14/2003	61.374	193,446
2	6/15/2003	57.086	189,912
2	6/16/2003	55.164	189,091
2	6/17/2003	62.629	196,250
2	6/18/2003	64.786	189,691
2	6/19/2003	73.637	211,207
2	6/20/2003	63.431	197,470
2	6/21/2003	63.918	197,410
2	6/22/2003	64.29	198,094
2	6/23/2003	75.428	227,341
2	6/24/2003	66.436	202,040
2	6/25/2003	72.313	226,759
2	6/26/2003	66.525	197,524
2	6/27/2003	68.121	197,548
2	6/28/2003	63.802	200,025
2	6/29/2003	77.756	220,554
2	6/30/2003	52.714	170,043
2	7/1/2003	71.656	214,756
2	7/2/2003	63.08	186,501
2	7/3/2003	73.932	215,785
2	7/4/2003	60.631	178,823
2	7/5/2003	68.874	205,836
2	7/6/2003	61.564	178,612
2	7/7/2003	74.013	223,042
2	7/8/2003	67.694	208,792
2	7/9/2003	76.708	221,622
2	7/10/2003	68.181	197,469
2	7/11/2003	66.898	195,582
2	7/12/2003	59.027	207,695
2	7/13/2003	75.38	218,117
2	7/14/2003	69.033	203,421
2	7/15/2003	78.388	230,380
2	7/16/2003	74.257	203,521
2	7/17/2003	75.934	217,919
2	7/18/2003	68.109	191,966
2	7/19/2003	72.846	207,656
2	7/20/2003	61.14	178,396
2	7/21/2003	78.679	230,258
2	7/22/2003	62.621	195,532
2	7/23/2003	65.829	203,912
2	7/24/2003	60.599	178,711
2	7/25/2003	73.576	210,531
2	7/26/2003	70.157	197,491
2	7/27/2003	90.528	215,849
2	7/28/2003	68.841	191,139
2	7/29/2003	70.723	204,797
2	7/30/2003	67.712	197,828

2	7/31/2003	66.125	202,486
2	8/1/2003	71.541	196,492
2	8/2/2003	80.742	214,317
2	8/3/2003	61.329	168,613
2	8/4/2003	68.92	195,435
2	8/5/2003	61.499	178,308
2	8/6/2003	73.18	207,756
2	8/7/2003	69.856	190,980
2	8/8/2003	77.228	187,873
2	8/9/2003	72.809	191,248
2	8/10/2003	75.267	200,240
2	8/11/2003	60.618	154,754
2	8/12/2003	63.981	167,678
2	8/13/2003	74.526	186,716
2	8/14/2003	82.677	219,956
2	8/15/2003	69.953	198,724
2	8/16/2003	78.945	219,751
2	8/17/2003	84.556	185,941
2	8/18/2003	87.543	217,540
2	8/19/2003	74.519	199,463
2	8/20/2003	88.865	221,338
2	8/21/2003	70.209	187,889
2	8/22/2003	81.354	217,865
2	8/23/2003	77.177	179,597
2	8/24/2003	62.13	172,445
2	8/25/2003	68.592	194,288
2	8/26/2003	87.919	203,448
2	8/27/2003	80.932	216,513
2	8/28/2003	82.687	197,918
2	8/29/2003	82.208	202,540
2	8/30/2003	83.364	211,336
2	8/31/2003	65.314	183,922
2	9/1/2003	93.901	216,245
2	9/2/2003	67.103	195,437
2	9/3/2003	87.882	211,604
2	9/4/2003	73.831	185,708
2	9/5/2003	62.172	169,129
2	9/6/2003	69.933	172,549
2	9/7/2003	71.082	186,768
2	9/8/2003	67.777	194,007
2	9/9/2003	59.869	208,235
2	9/10/2003	47.297	191,134
2	9/11/2003	70.439	214,754
2	9/12/2003	68.502	194,246
2	9/13/2003	77.372	212,995
2	9/14/2003	62.285	185,112
2	9/15/2003	62.138	181,443

2	9/16/2003	54.365	159,836
2	9/17/2003	44.087	170,662
2	9/18/2003	64.266	179,510
2	9/19/2003	84.561	198,395
2	9/20/2003	61.237	175,201
2	9/21/2003	45.248	135,969
2	9/22/2003	64.048	184,563
2	9/23/2003	72.375	210,158
2	9/24/2003	67.512	190,162
2	9/25/2003	82.877	216,409
2	9/26/2003	66.416	195,764
2	9/27/2003	71.255	214,105
2	9/28/2003	48.564	144,440
2	10/1/2003	0.739	5,350
2	10/2/2003	33.504	91,269
2	10/3/2003	69.337	173,240
2	10/4/2003	70.961	181,775
2	10/5/2003	78.203	208,329
2	10/6/2003	75.187	201,250
2	10/7/2003	89.169	220,542
2	10/8/2003	49.203	193,751
2	10/9/2003	67.662	186,810
2	10/10/2003	79.918	191,964
2	10/11/2003	77.311	208,470
2	10/12/2003	55.02	133,243
2	10/13/2003	57.783	146,579
2	10/14/2003	57.2	158,381
2	10/15/2003	70.099	163,846
2	10/16/2003	39.172	119,677
2	10/17/2003	22.491	110,018
2	10/18/2003	28.818	111,833
2	10/19/2003	26.99	97,703
2	10/20/2003	47.314	136,379
2	10/21/2003	58.792	171,856
2	10/22/2003	44.082	123,176
2	10/23/2003	38.065	108,419
2	10/24/2003	46.912	121,940
2	10/25/2003	40.834	121,636
2	10/26/2003	41.361	134,381
2	10/27/2003	77.893	217,120
2	10/28/2003	81.213	189,818
2	10/29/2003	88.045	219,499
2	10/30/2003	69.841	189,813
2	10/31/2003	88.683	217,110
2	11/1/2003	73.396	187,086
2	11/2/2003	83.102	204,959
2	11/3/2003	78.948	190,234

2	11/4/2003	82.853	207,766
2	11/5/2003	80.004	205,747
2	11/6/2003	72.8	209,571
2	11/7/2003	68.317	179,234
2	11/8/2003	78.886	216,308
2	11/9/2003	66.667	184,689
2	11/10/2003	78.976	195,905
2	11/11/2003	52.075	130,022
2	11/12/2003	41.692	117,091
2	11/13/2003	11.611	36,258
2	11/17/2003	0.17	2,225
2	11/18/2003	38.966	117,867
2	11/19/2003	65.18	198,434
2	11/20/2003	71.803	194,782
2	11/21/2003	83.116	211,544
2	11/22/2003	70.553	193,300
2	11/23/2003	74.376	201,621
2	11/24/2003	77.352	199,592
2	11/25/2003	80.788	215,593
2	11/26/2003	63.023	192,250
2	11/27/2003	63.937	183,110
2	11/28/2003	68.873	184,297
2	11/29/2003	66.042	216,610
2	11/30/2003	46.244	167,797
2	12/1/2003	57.318	183,858
2	12/2/2003	63.35	181,812
2	12/3/2003	56.658	195,654
2	12/4/2003	65.813	180,092
2	12/5/2003	58.821	198,595
2	12/6/2003	54.429	201,880
2	12/7/2003	87.118	207,001
2	12/8/2003	61.162	166,563
2	12/9/2003	65.51	208,456
2	12/10/2003	73.371	197,599
2	12/11/2003	81.449	210,498
2	12/12/2003	60.767	176,633
2	12/13/2003	75.382	202,675
2	12/14/2003	68.046	166,486
2	12/15/2003	76.107	200,848
2	12/16/2003	59.007	163,400
2	12/17/2003	74.676	202,708
2	12/18/2003	80.577	193,320
2	12/19/2003	71.731	183,867
2	12/20/2003	71.602	216,101
2	12/21/2003	57.933	178,546
2	12/22/2003	56.158	161,064
2	12/23/2003	47.942	181,785

2	12/24/2003	56.125	196,775
2	12/25/2003	51.062	177,009
2	12/26/2003	54.125	196,221
2	12/27/2003	40.469	186,754
2	12/28/2003	41.98	191,214
2	12/29/2003	40.674	182,939
2	12/30/2003	44.935	209,032
2	12/31/2003	42.973	185,415
	Max (tpd) -->	**93.901**	
	Max (lb/hr) -->	**7825.1**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1	1/1/2009	0.2417	22.557	185,974
1	1/2/2009	0.229	21.102	183,955
1	1/3/2009	0.2418	21.9	178,066
1	1/4/2009	0.3366	29.789	180,075
1	1/5/2009	0.3364	31.511	187,206
1	1/6/2009	0.3416	32.861	192,024
1	1/7/2009	0.3303	31.933	193,023
1	1/8/2009	0.3044	29.676	194,965
1	1/9/2009	0.2255	20.636	182,247
1	1/10/2009	0.2662	18.387	144,944
1	1/11/2009	0.2362	20.178	172,039
1	1/12/2009	0.2348	22.039	186,247
1	1/13/2009	0.2088	16.731	158,242
1	1/14/2009	0.172	11.413	132,759
1	1/15/2009	0.1951	12.023	120,430
1	1/16/2009	0.2145	13.936	129,923
1	1/17/2009	0.1877	1.053	8,769
1	1/19/2009	0.0508	0.224	6,180
1	1/20/2009	0.2751	22.771	172,042
1	1/21/2009	0.2678	27.201	203,889
1	1/22/2009	0.2832	28.739	202,984
1	1/23/2009	0.2964	29.004	195,578
1	1/24/2009	0.2543	22.006	181,460
1	1/25/2009	0.2193	21.944	199,901
1	1/26/2009	0.2823	27.765	196,432
1	1/27/2009	0.2893	23.969	166,298
1	1/28/2009	0.2787	21.49	156,515
1	1/29/2009	0.2604	22.952	175,543
1	1/30/2009	0.2155	16.605	153,462
1	1/31/2009	0.2364	14.627	124,976
1	2/1/2009	0.252	20.969	166,864
1	2/2/2009	0.2503	19.149	155,816
1	2/3/2009	0.2304	21.501	187,220
1	2/4/2009	0.2326	21.196	182,571
1	2/5/2009	0.2295	18.233	156,315
1	2/6/2009	0.2191	21.27	194,417
1	2/7/2009	0.2425	22.265	187,834
1	2/8/2009	0.2223	22.37	201,308
1	2/9/2009	0.2375	23.27	195,674
1	2/10/2009	0.2649	24.645	185,718
1	2/11/2009	0.2936	26.569	180,885
1	2/12/2009	0.2832	27.88	197,109
1	2/13/2009	0.2948	29.084	197,610
1	2/14/2009	0.2948	23.967	165,802
1	2/15/2009	0.2688	25.925	193,017

1	2/16/2009	0.2419	22.894	189,774
1	2/17/2009	0.2365	22.752	193,112
1	2/18/2009	0.2326	20.909	179,771
1	2/19/2009	0.2327	16.466	129,297
1	2/20/2009	0.2777	24.159	173,092
1	2/21/2009	0.3317	28.161	172,865
1	2/22/2009	0.2971	26.247	177,509
1	2/23/2009	0.2568	24.565	191,481
1	2/24/2009	0.2597	24.822	190,964
1	2/25/2009	0.2659	23.68	178,208
1	2/26/2009	0.2962	26.941	181,698
1	2/27/2009	0.2946	25.36	175,220
1	2/28/2009	0.2531	21.377	170,065
1	3/1/2009	0.2629	25.952	197,521
1	3/2/2009	0.2688	26.674	198,445
1	3/3/2009	0.2677	26.519	198,236
1	3/4/2009	0.2792	26.801	190,996
1	3/5/2009	0.2172	20.312	186,838
1	3/6/2009	0.2316	23.537	202,821
1	3/7/2009	0.2378	18.594	157,394
1	3/8/2009	0.2346	21.958	187,077
1	3/9/2009	0.2279	20.968	181,867
1	3/10/2009	0.2394	23.077	190,866
1	3/11/2009	0.2459	24.583	200,550
1	3/12/2009	0.2488	22.693	182,849
1	3/13/2009	0.226	22.412	198,704
1	3/14/2009	0.2755	25.641	188,369
1	3/15/2009	0.242	23.083	191,574
1	3/16/2009	0.2407	23.256	193,804
1	3/17/2009	0.2453	23.086	189,229
1	3/18/2009	0.2315	23.342	201,601
1	3/19/2009	0.2322	22.393	192,481
1	3/20/2009	0.2223	21.275	190,261
1	3/21/2009	0.2848	25.606	182,647
1	3/22/2009	0.2231	20.163	180,672
1	3/23/2009	0.2219	20.184	182,865
1	3/24/2009	0.227	20.394	179,816
1	3/25/2009	0.2252	17.466	155,017
1	3/26/2009	0.3166	22.005	139,523
1	3/27/2009	0.2665	20.626	159,139
1	3/28/2009	0.2748	22.249	163,292
1	3/29/2009	0.2876	24.313	169,540
1	3/30/2009	0.2566	18.694	147,977
1	3/31/2009	0.2418	20.157	170,786
1	4/1/2009	0.2425	20.385	169,170
1	4/2/2009	0.2625	23.178	175,663
1	4/3/2009	0.2749	7.911	59,243

1	5/28/2009	0.0287	0.083	6,885
1	5/29/2009	0.0786	1.378	19,230
1	5/30/2009	0.2526	10.539	85,244
1	5/31/2009	0.0899	1.982	20,766
1	6/1/2009	0.26	15.038	122,900
1	6/3/2009	0.1327	7.661	62,957
1	6/4/2009	0.2477	16.053	138,038
1	6/5/2009	0.199	14.148	144,774
1	6/6/2009	0.2236	16.432	157,342
1	6/7/2009	0.2445	21.247	168,616
1	6/8/2009	0.2495	21.429	171,595
1	6/9/2009	0.2165	18.829	176,195
1	6/10/2009	0.2166	19.84	182,888
1	6/11/2009	0.2525	19.041	152,239
1	6/12/2009	0.2261	15.507	129,907
1	6/13/2009	0.229	16.4	148,419
1	6/14/2009	0.2191	15.878	147,645
1	6/15/2009	0.2167	19.406	175,677
1	6/16/2009	0.2202	18.626	167,794
1	6/17/2009	0.2194	20.474	186,024
1	6/18/2009	0.224	19.253	172,835
1	6/19/2009	0.227	20.813	184,848
1	6/20/2009	0.2731	24.007	177,114
1	6/21/2009	0.2538	24.095	191,110
1	6/22/2009	0.2253	21.912	194,107
1	6/23/2009	0.2313	22.821	197,316
1	6/24/2009	0.2539	24.536	192,962
1	6/25/2009	0.27	25.93	192,250
1	6/26/2009	0.2407	22.151	183,922
1	6/27/2009	0.2341	23.052	196,801
1	6/28/2009	0.2227	18.801	169,557
1	6/29/2009	0.214	16.968	157,727
1	6/30/2009	0.2357	16.931	140,820
1	7/1/2009	0.2701	21.895	161,488
1	7/2/2009	0.2266	19.26	169,047
1	7/3/2009	0.2322	21.273	183,230
1	7/4/2009	0.2604	19.154	152,742
1	7/5/2009	0.2276	17.629	153,938
1	7/6/2009	0.2195	18.51	168,092
1	7/7/2009	0.2192	20.064	182,222
1	7/8/2009	0.2178	19.794	180,994
1	7/9/2009	0.2311	21.53	185,874
1	7/10/2009	0.2643	23.126	180,863
1	7/11/2009	0.231	21.777	187,959
1	7/12/2009	0.2395	22.676	188,909
1	7/13/2009	0.2328	22.305	191,569
1	7/14/2009	0.2259	19.839	174,964

1	7/15/2009	0.2104	18.974	178,437
1	7/16/2009	0.279	24.991	178,594
1	7/17/2009	0.268	22.174	163,644
1	7/18/2009	0.3062	21.149	139,841
1	7/19/2009	0.2583	15.447	131,234
1	7/20/2009	0.2221	17.685	157,902
1	7/21/2009	0.2088	17.162	162,416
1	7/22/2009	0.2248	18.977	168,446
1	7/23/2009	0.2218	21.006	189,176
1	7/24/2009	0.2592	22.812	174,486
1	7/25/2009	0.2445	19.792	172,882
1	7/26/2009	0.2194	19.74	178,570
1	7/27/2009	0.2739	25.05	184,085
1	7/28/2009	0.2653	23.752	178,477
1	7/29/2009	0.259	22.421	173,100
1	7/30/2009	0.2096	14.423	137,320
1	8/1/2009	0.1339	5.494	51,274
1	8/2/2009	0.2293	20.221	176,461
1	8/3/2009	0.218	21.863	200,576
1	8/4/2009	0.2283	22.657	198,572
1	8/5/2009	0.2138	20.259	189,372
1	8/6/2009	0.217	19.174	176,305
1	8/7/2009	0.2181	20.147	184,761
1	8/8/2009	0.2771	24.472	177,359
1	8/9/2009	0.2812	27.31	193,766
1	8/10/2009	0.2857	28.233	197,731
1	8/11/2009	0.2744	26.897	196,156
1	8/12/2009	0.2698	24.817	182,817
1	8/13/2009	0.269	24.551	181,456
1	8/14/2009	0.2743	26.741	195,153
1	8/15/2009	0.2836	24.237	174,577
1	8/16/2009	0.2333	22.542	193,038
1	8/17/2009	0.272	26.42	194,019
1	8/18/2009	0.2321	21.397	184,088
1	8/19/2009	0.2271	20.926	183,818
1	8/20/2009	0.236	20.698	175,508
1	8/21/2009	0.2556	21.222	164,035
1	8/22/2009	0.2527	20.179	166,278
1	8/23/2009	0.288	22.807	161,085
1	8/24/2009	0.2919	24.46	167,101
1	8/25/2009	0.2717	23.916	175,933
1	8/26/2009	0.2889	25.766	177,843
1	8/27/2009	0.2782	25.141	180,206
1	8/28/2009	0.2753	26.642	193,609
1	8/29/2009	0.2828	23.682	169,967
1	8/30/2009	0.2709	22.767	171,656
1	8/31/2009	0.2385	20.603	172,786

1	9/1/2009	0.2895	23.532	165,149
1	9/2/2009	0.2393	20.326	171,089
1	9/3/2009	0.2754	25.441	182,556
1	9/4/2009	0.2936	28.943	197,227
1	9/5/2009	0.2339	19.971	172,357
1	9/6/2009	0.2321	20.473	176,563
1	9/7/2009	0.2785	23.08	166,814
1	9/8/2009	0.2849	26.244	182,516
1	9/9/2009	0.2972	29.066	195,567
1	9/10/2009	0.3008	29.164	193,968
1	9/11/2009	0.2925	27.837	190,060
1	9/12/2009	0.309	25.17	164,710
1	9/13/2009	0.2767	22.257	159,705
1	9/14/2009	0.2844	26.049	182,422
1	9/15/2009	0.2845	27.594	193,972
1	9/16/2009	0.2789	26.122	187,725
1	9/17/2009	0.2723	26.244	192,695
1	9/18/2009	0.2669	25.69	192,762
1	9/19/2009	0.2603	21.785	172,989
1	9/20/2009	0.2673	24.945	185,873
1	9/21/2009	0.2783	27.284	196,072
1	9/22/2009	0.2793	24.525	174,692
1	9/23/2009	0.2764	25.169	181,883
1	9/24/2009	0.2818	23.014	163,024
1	9/25/2009	0.254	22.424	176,232
1	9/26/2009	0.3217	25.439	164,445
1	9/27/2009	0.2624	22.396	171,350
1	9/28/2009	0.244	21.716	178,652
1	9/29/2009	0.2477	20.784	169,790
1	9/30/2009	0.2524	20.863	169,604
1	10/1/2009	0.2411	22.513	186,683
1	10/2/2009	0.2325	20.856	179,414
1	10/3/2009	0.1313	0.598	6,060
1	10/7/2009	0.0181	0.035	3,276
1	10/8/2009	0.103	2.601	27,845
1	10/9/2009	0.2059	18.142	175,119
1	10/10/2009	0.2194	20.806	190,259
1	10/11/2009	0.2098	19.8	188,683
1	10/12/2009	0.2499	24.099	192,840
1	10/13/2009	0.2572	24.66	191,558
1	10/14/2009	0.217	19.215	177,612
1	10/15/2009	0.2197	20.66	188,342
1	10/16/2009	0.2181	16.934	146,061
1	10/17/2009	0.2859	26.442	184,801
1	10/18/2009	0.2393	18.891	157,944
1	10/19/2009	0.2471	22.67	183,876
1	10/20/2009	0.2434	23.219	190,813

1	10/21/2009	0.2457	22.037	178,846
1	10/22/2009	0.2437	23.546	193,233
1	10/23/2009	0.2342	21.505	183,381
1	10/24/2009	0.2778	21.986	164,660
1	10/25/2009	0.261	23.63	180,733
1	10/26/2009	0.282	25.897	181,600
1	10/27/2009	0.2388	22.245	186,229
1	10/28/2009	0.2646	23.03	173,453
1	10/29/2009	0.2612	25.197	192,993
1	10/30/2009	0.2969	25.771	173,152
1	10/31/2009	0.275	20.524	155,484
1	11/1/2009	0.24	20.422	170,338
1	11/2/2009	0.2407	21.915	181,037
1	11/3/2009	0.2439	23.658	193,988
1	11/4/2009	0.2441	24.191	198,227
1	11/5/2009	0.2408	23.14	192,201
1	11/6/2009	0.239	23.424	195,972
1	11/7/2009	0.3008	26.77	179,558
1	11/8/2009	0.2839	27.824	196,035
1	11/9/2009	0.2309	22.044	191,074
1	11/10/2009	0.2232	21.629	193,791
1	11/11/2009	0.2322	21.276	183,505
1	11/12/2009	0.2323	21.877	188,405
1	11/13/2009	0.2235	21.093	188,761
1	11/14/2009	0.2407	19.833	169,629
1	11/15/2009	0.2398	21.074	178,440
1	11/16/2009	0.2416	22.088	182,498
1	11/17/2009	0.2444	22.727	185,298
1	11/18/2009	0.2675	25.5	190,795
1	11/19/2009	0.2644	24.905	187,826
1	11/20/2009	0.2558	25.076	196,091
1	11/21/2009	0.2614	25.879	198,002
1	11/22/2009	0.2866	25.585	180,892
1	11/23/2009	0.2669	25.978	194,669
1	11/24/2009	0.2643	25.777	195,036
1	11/25/2009	0.2674	26.216	196,066
1	11/26/2009	0.2421	22.007	181,702
1	11/27/2009	0.2024	19.373	191,302
1	11/28/2009	0.2262	19.388	176,586
1	11/29/2009	0.2126	21.011	197,657
1	11/30/2009	0.2246	21.342	191,357
1	12/1/2009	0.235	22.887	194,779
1	12/2/2009	0.2278	21.908	192,199
1	12/3/2009	0.2326	23.514	202,177
1	12/4/2009	0.2377	23.785	200,205
1	12/5/2009	0.2578	21.824	175,921
1	12/6/2009	0.2358	22.975	194,875

1	12/7/2009	0.2438	22.599	185,385
1	12/8/2009	0.2312	22.272	192,772
1	12/9/2009	0.2334	22.255	191,311
1	12/10/2009	0.2236	22.199	198,546
1	12/11/2009	0.2138	20.299	190,078
1	12/12/2009	0.2895	23.82	168,420
1	12/13/2009	0.2328	18.793	164,736
1	12/14/2009	0.217	20.137	184,394
1	12/15/2009	0.2241	21.809	194,862
1	12/16/2009	0.2255	21.731	192,781
1	12/17/2009	0.2121	20.822	196,522
1	12/18/2009	0.224	20.335	181,966
1	12/19/2009	0.2375	20.414	175,193
1	12/20/2009	0.2233	21.12	189,243
1	12/21/2009	0.2246	21.168	188,467
1	12/22/2009	0.2485	23.497	188,998
1	12/23/2009	0.2691	26.104	194,235
1	12/24/2009	0.2794	14.639	114,166
1	12/25/2009	0.0621	0.925	15,502
1	12/26/2009	0.2232	20.471	182,723
1	12/27/2009	0.2245	21.517	191,879
1	12/28/2009	0.217	20.65	190,240
1	12/29/2009	0.2149	21.123	196,616
1	12/30/2009	0.2244	21.379	190,648
1	12/31/2009	0.2446	22.456	183,231
1	1/1/2010	0.2255	21.167	187,682
1	1/2/2010	0.2472	21.08	175,457
1	1/3/2010	0.2242	21.432	191,270
1	1/4/2010	0.2109	20.432	193,792
1	1/5/2010	0.2211	21.426	193,808
1	1/6/2010	0.2386	18.882	165,099
1	1/7/2010	0.221	19.644	176,462
1	1/8/2010	0.2114	17.623	163,427
1	1/9/2010	0.2193	20.508	187,241
1	1/10/2010	0.2208	20.749	187,960
1	1/11/2010	0.2365	22.163	187,485
1	1/12/2010	0.2453	23.306	189,615
1	1/13/2010	0.297	28.967	194,558
1	1/14/2010	0.2842	27.53	193,543
1	1/15/2010	0.2856	28.326	198,336
1	1/16/2010	0.2991	25.997	177,113
1	1/17/2010	0.2743	25.113	182,520
1	1/18/2010	0.279	24.438	174,657
1	1/19/2010	0.2733	24.846	181,325
1	1/20/2010	0.2664	23.481	175,532
1	1/21/2010	0.274	24.503	177,916
1	1/22/2010	0.2829	26.412	186,815

1	1/23/2010	0.243	19.837	165,166
1	1/24/2010	0.2338	20.511	175,806
1	1/25/2010	0.2278	22.615	198,554
1	1/26/2010	0.2249	22.198	197,377
1	1/27/2010	0.2165	19.971	184,713
1	1/28/2010	0.2849	27.012	189,575
1	1/29/2010	0.2828	25.113	176,670
1	1/30/2010	0.2876	22.229	154,818
1	1/31/2010	0.2515	22.09	148,725
1	2/1/2010	0.2703	25.648	176,129
1	2/2/2010	0.2992	27.251	182,544
1	2/3/2010	0.275	27.686	201,338
1	2/4/2010	0.2721	27.138	199,542
1	2/5/2010	0.2478	23.519	190,047
1	2/6/2010	0.2328	20.58	182,706
1	2/7/2010	0.224	20.72	187,002
1	2/8/2010	0.2207	21.21	192,460
1	2/9/2010	0.2625	22.6	170,525
1	2/10/2010	0.2496	24.191	193,793
1	2/11/2010	0.2535	24.713	195,079
1	2/12/2010	0.2606	25.127	192,890
1	2/13/2010	0.2875	24.965	175,028
1	2/14/2010	0.2655	25.665	193,162
1	2/15/2010	0.2664	26.05	195,651
1	2/16/2010	0.2698	26.075	193,291
1	2/17/2010	0.2835	27.085	191,050
1	2/18/2010	0.2786	25.657	184,026
1	2/19/2010	0.2704	24.66	184,949
1	2/20/2010	0.105	0.977	10,224
1	3/21/2010	0.0201	0.083	7,244
1	3/22/2010	0.1987	7.368	66,506
1	3/23/2010	0.1843	16.561	181,217
1	3/24/2010	0.1821	18.207	199,792
1	3/25/2010	0.194	18.609	193,014
1	3/26/2010	0.2142	21.415	199,711
1	3/27/2010	0.1965	17.51	184,033
1	3/28/2010	0.1796	17.291	193,052
1	3/29/2010	0.1676	16.833	200,835
1	3/30/2010	0.1735	16.877	195,738
1	3/31/2010	0.1718	17.426	202,869
1	4/1/2010	0.1728	16.812	195,291
1	4/2/2010	0.1737	16.811	194,109
1	4/3/2010	0.1388	4.837	42,477
1	4/4/2010	0.1594	11.931	134,220
1	4/5/2010	0.1843	18.174	197,060
1	4/6/2010	0.1902	19.021	199,982
1	4/7/2010	0.1808	17.778	196,771

1	4/8/2010	0.1835	17.509	191,422
1	4/9/2010	0.1862	17.693	190,318
1	4/10/2010	0.228	19.36	174,659
1	4/11/2010	0.2044	19.104	188,655
1	4/12/2010	0.19	18.486	195,273
1	4/13/2010	0.2028	18.624	187,867
1	4/14/2010	0.2214	22.472	202,716
1	4/15/2010	0.2516	24.652	196,234
1	4/16/2010	0.2648	25.092	189,530
1	4/17/2010	0.2157	17.869	171,836
1	4/18/2010	0.2518	22.823	180,405
1	4/19/2010	0.259	23.98	185,074
1	4/20/2010	0.2578	24.199	187,740
1	4/21/2010	0.2654	25.315	190,730
1	4/22/2010	0.2631	25.777	195,921
1	4/23/2010	0.2647	25.062	189,340
1	4/24/2010	0.2699	21.67	162,829
1	4/25/2010	0.2553	23.076	180,663
1	4/26/2010	0.2689	25.284	187,997
1	4/27/2010	0.2529	24.266	192,112
1	4/28/2010	0.2435	24.092	197,625
1	4/29/2010	0.2153	20.848	193,827
1	4/30/2010	0.2161	21.827	202,101
1	5/1/2010	0.2627	23.583	181,531
1	5/2/2010	0.2089	21.664	207,393
1	5/3/2010	0.25	25.62	205,100
1	5/4/2010	0.2575	25.729	199,527
1	5/5/2010	0.2416	23.278	191,991
1	5/6/2010	0.2315	23.214	200,811
1	5/7/2010	0.2694	27.233	202,258
1	5/8/2010	0.2733	25.744	190,707
1	5/9/2010	0.2963	27.154	184,815
1	5/10/2010	0.2247	22.817	203,258
1	5/11/2010	0.2684	26.112	199,306
1	5/12/2010	0.2552	26.633	208,659
1	5/13/2010	0.2555	25.429	199,001
1	5/14/2010	0.2523	26.851	212,840
1	5/15/2010	0.25	23.115	188,487
1	5/16/2010	0.2388	24.284	203,473
1	5/17/2010	0.2402	24.465	203,525
1	5/18/2010	0.2502	25.344	202,638
1	5/19/2010	0.2603	26.042	199,883
1	5/20/2010	0.2413	24.035	199,037
1	5/21/2010	0.2449	24.816	202,660
1	5/22/2010	0.2607	23.546	184,935
1	5/23/2010	0.2441	26.169	214,435
1	5/24/2010	0.2526	26.032	205,992

1	5/25/2010	0.2518	25.772	204,656
1	5/26/2010	0.2464	24.331	196,980
1	5/27/2010	0.2496	25.909	207,626
1	5/28/2010	0.2353	22.017	185,447
1	5/29/2010	0.2644	23.718	180,639
1	5/30/2010	0.2595	23.648	182,486
1	5/31/2010	0.2593	25.021	191,134
1	6/1/2010	0.2641	27.579	207,957
1	6/2/2010	0.2546	27.177	213,484
1	6/3/2010	0.2455	23.534	189,871
1	6/6/2010	0.1503	11.423	95,868
1	6/7/2010	0.2485	25.341	203,099
1	6/8/2010	0.2484	26.455	212,998
1	6/9/2010	0.2488	25.949	208,623
1	6/10/2010	0.275	29.23	212,646
1	6/11/2010	0.2842	29.996	210,952
1	6/12/2010	0.2451	23.58	192,764
1	6/13/2010	0.2509	26.557	211,620
1	6/14/2010	0.24	25.088	209,081
1	6/15/2010	0.2763	28.133	203,272
1	6/16/2010	0.275	28.614	208,149
1	6/17/2010	0.266	27.845	209,373
1	6/18/2010	0.2703	28.041	207,522
1	6/19/2010	0.2934	27.652	189,156
1	6/20/2010	0.2922	30.563	209,187
1	6/21/2010	0.2885	30.561	211,832
1	6/22/2010	0.2844	28.471	199,716
1	6/23/2010	0.2758	27.324	197,144
1	6/24/2010	0.27	28.11	208,190
1	6/25/2010	0.2548	26.307	206,529
1	6/26/2010	0.2746	25.234	186,579
1	6/27/2010	0.259	26.651	205,554
1	6/28/2010	0.2641	27.109	205,362
1	6/29/2010	0.2663	27.287	205,077
1	6/30/2010	0.2635	27.147	206,030
1	7/1/2010	0.2596	26.917	207,354
1	7/2/2010	0.2391	24.64	206,221
1	7/3/2010	0.2528	22.579	183,539
1	7/4/2010	0.2474	25.063	202,228
1	7/5/2010	0.2432	24.872	204,498
1	7/6/2010	0.282	28.964	205,475
1	7/7/2010	0.2782	28.761	206,738
1	7/8/2010	0.279	29.277	209,878
1	7/9/2010	0.2808	29.026	206,709
1	7/10/2010	0.3021	28.47	188,958
1	7/11/2010	0.2915	29.614	203,030
1	7/12/2010	0.2835	28.878	203,711

1	7/13/2010	0.255	23.689	183,736
1	7/14/2010	0.2803	28.11	200,418
1	7/15/2010	0.2795	28.962	207,259
1	7/16/2010	0.2609	25.521	195,534
1	7/17/2010	0.28	25.098	180,246
1	7/18/2010	0.2653	25.887	194,004
1	7/19/2010	0.2645	26.17	197,810
1	7/20/2010	0.2578	24.882	192,669
1	7/21/2010	0.2676	26.094	194,914
1	7/22/2010	0.2393	22.75	188,229
1	7/23/2010	0.2103	20.808	197,760
1	7/24/2010	0.2269	18.969	175,143
1	7/25/2010	0.2214	21.322	194,389
1	7/26/2010	0.2356	24.52	207,912
1	7/27/2010	0.2179	20.532	187,760
1	7/28/2010	0.2498	22.324	176,755
1	7/29/2010	0.256	25.736	200,983
1	7/30/2010	0.2568	25.573	198,910
1	7/31/2010	0.311	29.639	191,293
1	8/1/2010	0.2794	28.948	207,134
1	8/2/2010	0.2789	28.839	206,544
1	8/3/2010	0.2832	30.087	212,590
1	8/4/2010	0.2669	28.321	212,274
1	8/5/2010	0.2843	28.321	199,293
1	8/6/2010	0.3009	30.435	201,985
1	8/7/2010	0.2324	21.7	188,963
1	8/8/2010	0.2139	21.677	203,123
1	8/9/2010	0.2075	18.951	182,041
1	8/10/2010	0.2226	22.429	201,886
1	8/11/2010	0.2355	19.065	162,431
1	8/12/2010	0.2611	25.678	195,833
1	8/13/2010	0.2678	23.715	180,693
1	8/14/2010	0.2618	20.084	155,737
1	8/15/2010	0.2574	23.858	182,175
1	8/16/2010	0.2257	17.033	148,284
1	8/17/2010	0.2456	22.964	186,131
1	8/18/2010	0.222	18.659	167,918
1	8/19/2010	0.2218	21.829	196,812
1	8/20/2010	0.2172	20.633	189,236
1	8/21/2010	0.2232	20.823	190,519
1	8/22/2010	0.2424	25.208	207,480
1	8/23/2010	0.2075	20.834	200,692
1	8/24/2010	0.2227	22.663	203,579
1	8/25/2010	0.2298	22.997	199,797
1	8/26/2010	0.2856	29.761	208,340
1	8/27/2010	0.2811	29.603	210,589
1	8/28/2010	0.2958	28.791	196,519

1	8/29/2010	0.2801	28.725	205,089
1	8/30/2010	0.2704	28.33	209,586
1	8/31/2010	0.2646	27.699	209,384
1	9/1/2010	0.2722	28.265	207,699
1	9/2/2010	0.2639	27.717	210,090
1	9/3/2010	0.2751	28.493	207,171
1	9/4/2010	0.229	20.452	181,873
1	9/5/2010	0.2362	18.821	166,586
1	9/6/2010	0.2136	19.503	180,968
1	9/7/2010	0.2181	22.5	206,398
1	9/8/2010	0.219	22.125	202,297
1	9/9/2010	0.2172	21.891	201,643
1	9/10/2010	0.2271	23.876	210,145
1	9/11/2010	0.2981	29.211	194,520
1	9/12/2010	0.3042	30.691	201,350
1	9/13/2010	0.2831	27.855	196,057
1	9/14/2010	0.2443	23.41	192,607
1	9/15/2010	0.2952	28.846	193,737
1	9/16/2010	0.2925	30.161	206,219
1	9/17/2010	0.2794	28.594	204,671
1	9/18/2010	0.2954	27.328	189,977
1	9/19/2010	0.2806	27.332	194,854
1	9/20/2010	0.2732	27.685	202,718
1	9/21/2010	0.2832	29.207	206,223
1	9/22/2010	0.2922	30.047	205,699
1	9/23/2010	0.2785	28.874	207,392
1	9/24/2010	0.2737	28.257	206,512
1	9/25/2010	0.294	27.525	188,132
1	9/26/2010	0.2893	27.046	186,762
1	9/27/2010	0.25	22.598	183,103
1	9/28/2010	0.2439	23.748	195,172
1	9/29/2010	0.2505	22.465	185,011
1	9/30/2010	0.2404	21.511	183,748
1	10/1/2010	0.2294	23.508	205,060
1	10/2/2010	0.2288	21.437	188,776
1	10/3/2010	0.2259	21.641	192,327
1	10/4/2010	0.2856	27.984	195,610
1	10/5/2010	0.2834	29.092	205,354
1	10/6/2010	0.2862	28.692	200,593
1	10/7/2010	0.2824	28.298	200,537
1	10/8/2010	0.2802	29.073	207,529
1	10/9/2010	0.292	27.867	190,877
1	10/10/2010	0.2769	28.683	207,054
1	10/11/2010	0.2459	24.448	199,999
1	10/12/2010	0.2136	20.95	195,506
1	10/13/2010	0.2154	21.868	202,773
1	10/14/2010	0.2196	21.985	200,529

1	10/15/2010	0.2204	21.505	195,926
1	10/16/2010	0.2917	27.461	188,175
1	10/17/2010	0.2618	23.545	183,396
1	10/18/2010	0.2446	25.17	205,989
1	10/19/2010	0.2188	20.826	191,391
1	10/20/2010	0.224	22.764	203,360
1	10/21/2010	0.2309	23.088	201,067
1	10/22/2010	0.2318	23.651	204,159
1	10/23/2010	0.235	21.697	186,421
1	10/24/2010	0.24	23.459	196,188
1	10/25/2010	0.2665	22.188	169,915
1	10/26/2010	0.2359	19.292	165,852
1	10/27/2010	0.2318	20.855	180,684
1	10/28/2010	0.2406	22.741	189,539
1	10/29/2010	0.2455	23.099	188,395
1	10/30/2010	0.2967	27.207	185,547
1	10/31/2010	0.2561	21.88	175,138
1	11/1/2010	0.2347	22.033	189,015
1	11/2/2010	0.277	26.873	194,078
1	11/3/2010	0.285	28.206	198,065
1	11/4/2010	0.3434	20.56	124,880
1	11/5/2010	0.241	21.14	172,918
1	11/6/2010	0.2381	21.488	184,218
1	11/7/2010	0.2274	20.738	183,946
1	11/8/2010	0.2383	23.397	196,588
1	11/9/2010	0.2398	22.365	187,077
1	11/10/2010	0.2361	21.876	186,398
1	11/11/2010	0.2535	19.769	154,191
1	11/12/2010	0.2768	27.724	200,178
1	11/13/2010	0.2898	24.397	171,689
1	11/14/2010	0.2768	26.116	188,681
1	11/15/2010	0.2703	25.702	189,586
1	11/16/2010	0.2877	21.164	149,409
1	11/17/2010	0.1694	5.503	55,507
1	11/18/2010	0.2278	20.195	177,298
1	11/19/2010	0.2353	21.078	180,626
1	11/20/2010	0.2288	20.684	183,259
1	11/21/2010	0.2258	21.767	193,751
1	11/22/2010	0.2905	27.242	188,178
1	11/23/2010	0.3445	13.456	80,656
1	11/24/2010	0.2676	8.61	65,010
1	11/25/2010	0.2434	18.831	157,963
1	11/26/2010	0.2239	19.222	170,019
1	11/27/2010	0.2383	21.741	183,949
1	11/28/2010	0.2398	20.67	173,911
1	11/29/2010	0.2239	21.048	187,884
1	11/30/2010	0.2323	22.708	194,543

1	12/1/2010	0.2416	24.592	203,637
1	12/2/2010	0.2433	22.339	184,162
1	12/3/2010	0.2371	24.03	202,866
1	12/4/2010	0.2331	23.785	204,109
1	12/5/2010	0.2478	22.067	184,403
1	12/6/2010	0.2543	26.265	206,875
1	12/7/2010	0.2663	25.039	187,245
1	12/8/2010	0.293	28.38	194,102
1	12/9/2010	0.2817	26.434	183,511
1	12/10/2010	0.2875	27.647	191,913
1	12/11/2010	0.256	22.286	177,015
1	12/12/2010	0.2492	24.616	197,914
1	12/13/2010	0.2475	24.822	200,824
1	12/14/2010	0.2296	19.921	171,815
1	12/15/2010	0.285	27.567	193,842
1	12/16/2010	0.2455	20.802	170,358
1	12/17/2010	0.2324	21.843	190,273
1	12/18/2010	0.2613	21.366	170,576
1	12/19/2010	0.2424	22.605	186,984
1	12/20/2010	0.2312	22.482	194,653
1	12/21/2010	0.23	21.245	185,043
1	12/22/2010	0.2856	25.944	181,207
1	12/23/2010	0.2844	27.014	190,152
1	12/24/2010	0.2795	24.808	177,347
1	12/25/2010	0.2407	19.198	164,425
1	12/26/2010	0.2235	21.217	190,308
1	12/27/2010	0.2313	20.666	179,642
1	12/28/2010	0.2375	21.652	182,546
1	12/29/2010	0.2645	25.449	190,736
1	12/30/2010	0.277	23.855	171,533
1	12/31/2010	0.3026	26.151	173,570
1	1/1/2011	0.2744	21.536	156,218
1	1/2/2011	0.2672	23.105	172,336
1	1/3/2011	0.2753	27	196,242
1	1/4/2011	0.2806	26.048	185,438
1	1/5/2011	0.2575	23.648	183,496
1	1/6/2011	0.2365	22.322	189,487
1	1/7/2011	0.2353	22.8	194,000
1	1/8/2011	0.2947	27.576	186,016
1	1/9/2011	0.3177	31.251	196,676
1	1/10/2011	0.3198	31.702	198,103
1	1/11/2011	0.3328	30.367	182,314
1	1/12/2011	0.3181	32.243	203,185
1	1/13/2011	0.2867	27.99	194,900
1	1/14/2011	0.2786	24.58	173,679
1	1/15/2011	0.327	30.171	187,100
1	1/16/2011	0.3086	30.303	196,273

1	1/17/2011	0.256	26.117	204,260
1	1/18/2011	0.2441	23.742	194,861
1	1/19/2011	0.2426	25.2	207,769
1	1/20/2011	0.2318	24.361	210,154
1	1/21/2011	0.2457	25.702	209,251
1	1/22/2011	0.2451	20.654	171,748
1	1/23/2011	0.2604	24.549	188,781
1	1/24/2011	0.227	21.365	189,609
1	1/25/2011	0.2405	24.748	205,811
1	1/26/2011	0.2602	25.822	198,511
1	1/27/2011	0.2867	25.786	179,872
1	1/28/2011	0.2598	26.364	202,981
1	1/29/2011	0.2598	22.796	176,057
1	1/30/2011	0.2678	24.491	184,992
1	1/31/2011	0.2594	25.458	196,838
1	2/1/2011	0.248	24.14	194,921
1	2/2/2011	0.256	24.036	186,626
1	2/3/2011	0.2923	6.742	50,057
1	2/7/2011	0.0326	0.119	6,602
1	2/8/2011	0.258	14.579	114,382
1	2/9/2011	0.2642	23.684	178,339
1	2/10/2011	0.2757	23.783	172,219
1	2/11/2011	0.2694	25.17	187,353
1	2/12/2011	0.2474	20.674	169,900
1	2/13/2011	0.262	22.12	171,222
1	2/14/2011	0.2597	20.397	158,752
1	2/15/2011	0.2999	22.772	152,588
1	2/16/2011	0.3121	18.583	119,114
1	2/17/2011	0.2927	16.883	117,158
1	2/18/2011	0.2941	19.895	140,530
1	2/19/2011	0.2715	23.768	176,567
1	2/20/2011	0.2998	29.001	191,782
1	2/21/2011	0.3223	29.897	187,466
1	2/22/2011	0.3201	31.697	197,027
1	2/23/2011	0.3143	32.46	206,620
1	2/24/2011	0.3074	31.299	203,713
1	2/25/2011	0.289	28.713	201,221
1	2/26/2011	0.366	0.42	2,297
1	3/11/2011	0.0187	0.06	6,279
1	3/12/2011	0.1579	10.754	90,201
1	3/13/2011	0.2883	29.341	203,713
1	3/14/2011	0.2793	29.347	210,151
1	3/15/2011	0.2819	29.423	208,766
1	3/16/2011	0.2881	29.67	205,998
1	3/17/2011	0.2551	25.673	201,221
1	3/18/2011	0.2693	27.686	205,444
1	3/19/2011	0.2478	24.946	202,814

1	3/20/2011	0.2425	25.152	207,659
1	3/21/2011	0.2491	25.753	206,897
1	3/22/2011	0.2512	25.491	202,952
1	3/23/2011	0.3294	32.169	197,040
1	3/24/2011	0.3284	28.585	171,004
1	3/25/2011	0.3242	33.688	207,489
1	3/26/2011	0.3377	35.203	208,540
1	3/27/2011	0.3066	28.918	191,333
1	3/28/2011	0.2696	25.198	186,586
1	3/29/2011	0.2587	23.697	184,101
1	3/30/2011	0.2491	24.75	199,260
1	3/31/2011	0.2541	24.441	192,974
1	4/1/2011	0.2089	18.767	156,848
1	4/2/2011	0.3048	26.807	177,289
1	4/3/2011	0.3077	30.696	198,991
1	4/4/2011	0.2943	28.607	191,457
1	4/5/2011	0.2855	25.756	177,800
1	4/6/2011	0.251	25.47	203,163
1	4/7/2011	0.2511	25.93	206,684
1	4/8/2011	0.2607	27.166	209,541
1	4/9/2011	0.2617	27.56	210,651
1	4/10/2011	0.3235	30.564	193,483
1	4/11/2011	0.3025	24.518	162,199
1	4/12/2011	0.3081	18.537	120,044
1	4/13/2011	0.3173	26.756	169,180
1	4/14/2011	0.2785	29.024	208,382
1	4/15/2011	0.3225	21.052	135,124
1	4/16/2011	0.3033	23.975	159,188
1	4/17/2011	0.3225	21.95	140,316
1	4/18/2011	0.2923	28.136	193,723
1	4/19/2011	0.2926	27.145	187,623
1	4/20/2011	0.2662	26.325	199,464
1	4/21/2011	0.3068	25.387	166,261
1	4/22/2011	0.3052	27.694	180,982
1	4/23/2011	0.1818	13.913	96,641
1	4/24/2011	0.2565	21.49	146,069
1	4/25/2011	0.3061	25.211	167,085
1	4/26/2011	0.2926	28.505	194,483
1	4/27/2011	0.3103	29.212	187,361
1	4/28/2011	0.3153	33.476	212,167
1	4/29/2011	0.3142	32	202,245
1	4/30/2011	0.3348	31.344	193,614
1	5/1/2011	0.3035	31.286	205,693
1	5/2/2011	0.3157	29.217	188,517
1	5/3/2011	0.2953	30.087	203,771
1	5/4/2011	0.2882	30.358	210,564
1	5/5/2011	0.3253	33.008	203,050

1	5/6/2011	0.3303	32.479	197,656
1	5/7/2011	0.335	31.433	190,510
1	5/8/2011	0.3232	32.219	197,485
1	5/9/2011	0.3485	33.531	190,878
1	5/10/2011	0.3502	36.017	205,098
1	5/11/2011	0.3198	30.162	187,118
1	5/12/2011	0.3328	34.496	206,860
1	5/13/2011	0.3	25.255	166,465
1	5/14/2011	0.2685	22.316	166,620
1	5/15/2011	0.2583	20.237	156,706
1	5/16/2011	0.2401	23.336	195,978
1	5/17/2011	0.245	20.526	167,790
1	5/18/2011	0.3041	29.025	188,581
1	5/19/2011	0.3013	28.953	192,586
1	5/20/2011	0.2849	24.003	174,209
1	5/21/2011	0.3387	19.749	119,185
1	5/22/2011	0.3179	26.546	167,128
1	5/23/2011	0.2817	19.462	138,655
1	5/24/2011	0.2652	12.27	94,238
1	5/25/2011	0.3277	14.403	88,399
1	5/26/2011	0.3134	11.742	75,516
1	5/27/2011	0.2824	18.587	132,303
1	5/28/2011	0.2844	17.518	128,124
1	5/29/2011	0.2762	21.743	158,702
1	5/30/2011	0.2673	25.753	194,432
1	5/31/2011	0.2588	27.233	212,989
1	6/1/2011	0.2501	25.855	209,164
1	6/2/2011	0.2549	26.463	207,806
1	6/3/2011	0.304	33.777	222,247
1	6/4/2011	0.2468	23.901	201,577
1	6/5/2011	0.2215	23.022	194,071
1	6/6/2011	0.2938	17.844	123,104
1	6/7/2011	0.2529	22.972	180,960
1	6/8/2011	0.289	28.385	192,998
1	6/9/2011	0.2639	26.331	198,818
1	6/10/2011	0.2426	22.745	185,207
1	6/11/2011	0.2614	21.274	165,344
1	6/12/2011	0.285	21.684	162,833
1	6/13/2011	0.2448	23.68	192,365
1	6/14/2011	0.2439	24.562	200,470
1	6/15/2011	0.2418	26.31	217,535
1	6/16/2011	0.3014	29.69	196,018
1	6/17/2011	0.3077	31.325	202,696
1	6/18/2011	0.2494	21.733	176,490
1	6/19/2011	0.2443	19.919	162,985
1	6/20/2011	0.2401	17.898	148,992
1	6/21/2011	0.2552	26.63	208,883

1	6/22/2011	0.3066	30.557	198,190
1	6/23/2011	0.2923	27.879	190,172
1	6/24/2011	0.2943	28.55	193,016
1	6/25/2011	0.2772	25.397	190,278
1	6/26/2011	0.2567	26.21	206,105
1	6/27/2011	0.2488	27.561	221,597
1	6/28/2011	0.2837	27.863	194,319
1	6/29/2011	0.2798	26.347	187,317
1	6/30/2011	0.2873	30.244	210,121
1	7/1/2011	0.2909	30.598	210,254
1	7/2/2011	0.2971	32.532	218,892
1	7/3/2011	0.2991	27.738	188,972
1	7/4/2011	0.2654	22.959	174,073
1	7/5/2011	0.2439	23.389	190,364
1	7/6/2011	0.2513	26.535	211,123
1	7/7/2011	0.2504	26.951	215,346
1	7/8/2011	0.2533	27.767	219,197
1	7/9/2011	0.239	24.282	205,122
1	7/10/2011	0.2417	26.837	222,145
1	7/11/2011	0.2405	26.62	221,393
1	7/12/2011	0.2691	28.291	209,935
1	7/13/2011	0.2866	31.379	218,780
1	7/14/2011	0.2852	30.975	217,155
1	7/15/2011	0.2978	32.598	218,739
1	7/16/2011	0.303	30.545	202,319
1	7/17/2011	0.2943	31.621	214,289
1	7/18/2011	0.2935	32.197	219,095
1	7/19/2011	0.2508	26.214	209,355
1	7/20/2011	0.2438	26.822	220,143
1	7/21/2011	0.2373	26.004	219,243
1	7/22/2011	0.2316	25.712	221,899
1	7/23/2011	0.2612	26.251	207,145
1	7/24/2011	0.2442	26.09	214,034
1	7/25/2011	0.2436	25.395	208,556
1	7/26/2011	0.2933	31.12	210,499
1	7/27/2011	0.3134	10.128	66,037
1	7/29/2011	0.089	2.118	20,420
1	7/30/2011	0.2457	19.261	158,945
1	7/31/2011	0.2636	25.89	198,165
1	8/1/2011	0.2543	27.118	215,177
1	8/2/2011	0.2931	30.617	209,369
1	8/3/2011	0.2884	30.395	210,149
1	8/4/2011	0.3111	34.653	222,817
1	8/5/2011	0.3055	33.391	218,715
1	8/6/2011	0.2476	24.84	204,489
1	8/7/2011	0.2378	25.849	217,528
1	8/8/2011	0.24	26.288	219,150

1	8/9/2011	0.2348	25.06	213,851
1	8/10/2011	0.2389	25.277	212,023
1	8/11/2011	0.2506	24.41	196,750
1	8/12/2011	0.2346	24.911	213,060
1	8/13/2011	0.2855	27.835	194,252
1	8/14/2011	0.2836	29.626	207,997
1	8/15/2011	0.2905	28.901	196,583
1	8/16/2011	0.2593	26.475	205,376
1	8/17/2011	0.242	26.494	218,994
1	8/18/2011	0.2462	26.264	213,453
1	8/19/2011	0.246	26.58	216,304
1	8/20/2011	0.3125	31.158	202,466
1	8/21/2011	0.2984	31.718	212,613
1	8/22/2011	0.3041	32.923	216,539
1	8/23/2011	0.3016	32.883	218,035
1	8/24/2011	0.3044	29.698	194,978
1	8/25/2011	0.297	30.825	207,837
1	8/26/2011	0.2936	29.115	198,020
1	8/27/2011	0.3214	30.116	190,500
1	8/28/2011	0.2824	27.764	198,603
1	8/29/2011	0.2455	25.407	207,435
1	8/30/2011	0.3029	31.871	210,147
1	8/31/2011	0.3024	33.783	223,442
1	9/1/2011	0.2995	28.429	188,503
1	9/2/2011	0.275	27.589	198,660
1	9/3/2011	0.2956	29.259	200,164
1	9/4/2011	0.294	30.918	210,336
1	9/5/2011	0.335	28.566	171,987
1	9/6/2011	0.3073	22.283	157,653
1	9/7/2011	0.2566	22.851	181,872
1	9/8/2011	0.2522	23.43	187,528
1	9/9/2011	0.2672	24.381	186,087
1	9/10/2011	0.2612	24.521	192,639
1	9/11/2011	0.2345	24.68	211,851
1	9/12/2011	0.2929	15.006	102,976
1	9/13/2011	0.3017	11.17	75,172
1	9/15/2011	0.0121	0.031	3,566
1	9/16/2011	0.2529	22.791	169,360
1	9/17/2011	0.2808	29.152	208,051
1	9/18/2011	0.2764	28.756	207,730
1	9/19/2011	0.2666	28.215	211,593
1	9/20/2011	0.269	28.224	209,369
1	9/21/2011	0.2565	27.649	215,740
1	9/22/2011	0.2566	27.998	218,256
1	9/23/2011	0.265	26.895	203,117
1	9/24/2011	0.2555	23.691	185,965
1	9/25/2011	0.2568	25.174	195,549

1	9/26/2011	0.2658	26.646	200,705
1	9/27/2011	0.2838	29.077	204,780
1	9/28/2011	0.2901	30.027	207,673
1	9/29/2011	0.3062	27.442	179,335
1	9/30/2011	0.2993	24.304	165,646
1	10/1/2011	0.3272	28.377	172,370
1	10/2/2011	0.332	27.139	167,584
1	10/3/2011	0.299	27.784	185,830
1	10/4/2011	0.2973	26.108	185,301
1	10/5/2011	0.2848	28.83	202,563
1	10/6/2011	0.2912	29.672	203,710
1	10/7/2011	0.2583	20.305	158,190
1	12/1/2011	0.0344	0.276	12,257
1	12/2/2011	0.1488	2.584	19,245
1	12/3/2011	0.2449	7.913	67,100
1	12/4/2011	0.0213	0.064	5,278
1	12/5/2011	0.2395	3.643	27,954
1	12/6/2011	0.1552	11.391	97,526
1	12/7/2011	0.1832	6.469	54,040
1	12/8/2011	0.0355	0.24	12,053
1	12/9/2011	0.1425	4.276	35,345
1	12/10/2011	0.2094	18.036	166,221
1	12/11/2011	0.2645	26.706	201,593
1	12/12/2011	0.3437	27.04	159,061
1	12/13/2011	0.3433	21.816	130,345
1	12/14/2011	0.3019	21.065	140,785
1	12/15/2011	0.2904	22.341	156,132
1	12/16/2011	0.2785	25.628	184,586
1	12/17/2011	0.3318	25.227	154,770
1	12/18/2011	0.2967	26.504	178,319
1	12/19/2011	0.3098	25.612	164,932
1	12/20/2011	0.2955	26.485	178,182
1	12/21/2011	0.2774	23.53	176,338
1	12/22/2011	0.2623	19.466	151,302
1	12/23/2011	0.2683	20.937	163,070
1	12/24/2011	0.2581	18.565	145,510
1	12/25/2011	0.2963	17.234	117,109
1	12/26/2011	0.2589	19.485	156,074
1	12/27/2011	0.2525	18.381	147,026
1	12/28/2011	0.2361	18.315	157,262
1	12/29/2011	0.267	19.695	146,980
1	12/30/2011	0.2305	17.172	148,630
1	12/31/2011	0.2204	15.742	146,090
		Max (tpd) -->	**36.017**	
		Max (lb/hr) -->	**3001.4**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
2	1/1/2009	0.0261	0.091	5,640
2	1/2/2009	0.2909	18.42	127,323
2	1/3/2009	0.2318	13.585	119,933
2	1/8/2009	0.0775	1.118	12,624
2	1/9/2009	0.2739	23.517	171,068
2	1/10/2009	0.2507	20.168	162,382
2	1/11/2009	0.2739	22.223	163,644
2	1/12/2009	0.2975	29.043	193,510
2	1/13/2009	0.2893	26.767	181,728
2	1/14/2009	0.3188	32.754	205,116
2	1/15/2009	0.31	28.395	180,371
2	1/16/2009	0.3048	27.868	176,283
2	1/17/2009	0.2602	25.026	191,525
2	1/18/2009	0.2593	23.665	180,663
2	1/19/2009	0.3101	30.405	194,800
2	1/20/2009	0.3551	35.611	201,033
2	1/21/2009	0.3343	34.302	205,302
2	1/22/2009	0.3221	32.896	204,164
2	1/23/2009	0.3216	31.966	198,290
2	1/24/2009	0.2958	27.507	183,605
2	1/25/2009	0.3155	28.282	178,578
2	1/26/2009	0.2993	28.875	192,705
2	1/27/2009	0.3009	25.29	166,495
2	1/28/2009	0.2567	21.379	167,368
2	1/29/2009	0.2704	22.598	164,099
2	1/30/2009	0.2523	18.045	142,425
2	1/31/2009	0.2298	15.086	129,124
2	2/1/2009	0.2836	22.647	158,168
2	2/2/2009	0.3019	25.355	166,649
2	2/3/2009	0.2946	28.553	193,402
2	2/4/2009	0.2917	27.911	191,143
2	2/5/2009	0.278	24.888	178,569
2	2/6/2009	0.2869	24.119	169,541
2	3/10/2009	0.0153	0.055	5,142
2	3/11/2009	0.0995	2.116	27,663
2	3/12/2009	0.2269	11.877	105,805
2	3/13/2009	0.224	12.707	116,628
2	3/14/2009	0.278	24.624	174,313
2	3/15/2009	0.2862	28.461	198,920
2	3/16/2009	0.2786	23.489	162,301
2	3/17/2009	0.2813	28.246	200,711
2	3/18/2009	0.2543	24.712	192,237
2	3/19/2009	0.2388	22.403	186,664
2	3/20/2009	0.2793	26.931	192,324
2	3/21/2009	0.2939	28.949	196,639

2	3/22/2009	0.3368	25.926	160,754
2	3/23/2009	0.2891	27.445	185,615
2	3/24/2009	0.28	26.217	183,347
2	3/25/2009	0.2845	26.316	183,498
2	3/26/2009	0.2292	17.558	154,379
2	3/27/2009	0.2301	19.644	169,547
2	3/28/2009	0.2328	20.618	174,851
2	3/29/2009	0.2912	22.947	161,137
2	3/30/2009	0.2319	18.375	157,407
2	3/31/2009	0.2632	21.662	165,761
2	4/1/2009	0.2305	19.969	173,539
2	4/2/2009	0.2834	26.598	185,888
2	4/3/2009	0.2948	25.478	178,791
2	4/4/2009	0.2834	26.519	187,224
2	4/5/2009	0.2995	22.771	158,096
2	4/6/2009	0.2886	24.795	170,003
2	4/7/2009	0.2774	22.94	165,933
2	4/8/2009	0.2798	27.927	199,584
2	4/9/2009	0.2935	28.35	192,328
2	4/10/2009	0.2943	29.188	197,666
2	4/11/2009	0.2406	21.521	178,271
2	4/12/2009	0.2444	20.202	170,894
2	4/13/2009	0.2386	23.46	196,569
2	4/14/2009	0.235	21.614	183,468
2	4/15/2009	0.2654	25.425	189,209
2	4/16/2009	0.2962	29.264	197,585
2	4/17/2009	0.3001	29.528	196,034
2	4/18/2009	0.2917	26.649	181,591
2	4/19/2009	0.2607	20.281	163,877
2	4/20/2009	0.2765	20.982	151,331
2	4/21/2009	0.2872	18.688	134,224
2	4/22/2009	0.2946	19.749	140,507
2	4/23/2009	0.2872	20.909	147,977
2	4/24/2009	0.2655	21.91	165,115
2	4/25/2009	0.2919	26.843	185,377
2	4/26/2009	0.3163	26.158	174,199
2	4/27/2009	0.2764	27.239	196,737
2	4/28/2009	0.2998	26.418	179,218
2	4/29/2009	0.2612	25.324	193,188
2	4/30/2009	0.2669	24.279	182,477
2	5/1/2009	0.2713	26.87	197,305
2	5/2/2009	0.2759	25.246	182,506
2	5/3/2009	0.3023	24.906	169,518
2	5/4/2009	0.2453	24.406	199,418
2	5/5/2009	0.2289	22.984	200,712
2	5/6/2009	0.2312	24.118	208,634
2	5/7/2009	0.2237	21.628	192,131

2	5/8/2009	0.2238	20.322	184,264
2	5/10/2009	0.0475	0.316	6,652
2	5/13/2009	0.0345	0.095	5,089
2	5/14/2009	0.2212	15.754	144,287
2	5/15/2009	0.2099	19.947	188,515
2	5/16/2009	0.2342	22.483	192,186
2	5/17/2009	0.2663	17.789	143,453
2	5/18/2009	0.3109	16.009	119,022
2	5/19/2009	0.3356	23.757	148,024
2	5/20/2009	0.3431	27.769	172,398
2	5/21/2009	0.2713	25.308	187,292
2	5/22/2009	0.271	25.287	186,142
2	5/23/2009	0.2786	24.6	177,111
2	5/24/2009	0.2987	22.044	149,976
2	5/25/2009	0.3122	28.598	182,290
2	5/26/2009	0.2694	25.161	187,188
2	5/27/2009	0.2783	27.584	198,031
2	5/28/2009	0.2693	25.369	188,054
2	5/29/2009	0.2698	26.267	194,221
2	5/30/2009	0.2825	23.995	174,613
2	5/31/2009	0.3342	28.272	172,557
2	6/1/2009	0.266	23.483	178,127
2	6/2/2009	0.2611	25.715	196,721
2	6/3/2009	0.2533	22.715	179,806
2	6/4/2009	0.271	20.851	158,037
2	6/5/2009	0.2674	22.602	171,796
2	6/6/2009	0.2957	22.743	162,591
2	6/7/2009	0.2636	21.407	170,189
2	6/8/2009	0.2481	22.267	181,947
2	6/9/2009	0.2329	22.017	189,044
2	6/10/2009	0.2265	21.733	191,665
2	6/11/2009	0.2374	18.931	162,381
2	6/12/2009	0.2573	19.877	155,848
2	6/13/2009	0.2581	21.896	170,331
2	6/14/2009	0.2747	19.471	147,429
2	6/15/2009	0.2846	26.277	182,258
2	6/16/2009	0.2907	25.986	178,046
2	6/17/2009	0.3072	29.88	194,039
2	6/18/2009	0.2996	28.044	186,931
2	6/21/2009	0.1197	4.959	46,582
2	6/22/2009	0.2236	22.416	200,395
2	6/23/2009	0.2248	22.535	200,333
2	6/24/2009	0.2741	27.504	199,998
2	6/25/2009	0.3138	31.309	199,188
2	6/26/2009	0.2556	23.784	184,452
2	6/27/2009	0.2583	24.851	162,343
2	6/28/2009	0.2903	28.691	197,646

2	6/29/2009	0.263	22.635	171,126
2	6/30/2009	0.2483	19.334	151,681
2	7/1/2009	0.2656	23.073	169,900
2	7/2/2009	0.2575	23.22	177,500
2	7/3/2009	0.2675	22.222	166,394
2	7/4/2009	0.273	24.728	179,753
2	7/5/2009	0.2543	20.745	159,592
2	7/6/2009	0.2562	23.265	178,252
2	7/7/2009	0.2721	26.092	190,572
2	7/8/2009	0.3048	29.026	189,384
2	7/9/2009	0.3118	30.494	195,328
2	7/10/2009	0.3191	32.415	202,918
2	7/11/2009	0.3213	30.604	188,437
2	7/12/2009	0.3187	28.733	176,910
2	7/13/2009	0.3282	32.729	199,236
2	7/14/2009	0.2708	25.07	184,893
2	7/15/2009	0.2813	26.429	186,932
2	7/16/2009	0.2845	27.408	191,498
2	7/17/2009	0.2359	19.018	162,426
2	7/18/2009	0.2425	20.145	164,577
2	7/19/2009	0.2653	19.508	155,821
2	7/20/2009	0.236	21.72	184,119
2	7/21/2009	0.22	20.124	183,440
2	7/22/2009	0.274	24.392	173,242
2	7/23/2009	0.3088	30.97	200,132
2	7/24/2009	0.286	26.564	184,917
2	7/25/2009	0.2697	24.839	184,894
2	7/26/2009	0.2895	19.872	142,800
2	7/27/2009	0.2409	19.605	163,263
2	7/28/2009	0.246	20.557	164,855
2	7/29/2009	0.2853	23.79	166,403
2	7/30/2009	0.291	24.573	167,059
2	7/31/2009	0.3055	31.279	204,690
2	8/1/2009	0.2828	25.528	179,649
2	8/2/2009	0.2508	19.842	161,155
2	8/3/2009	0.245	24.245	198,288
2	8/4/2009	0.2352	23.658	201,238
2	8/5/2009	0.2216	20.975	188,904
2	8/6/2009	0.2191	20.001	182,055
2	8/7/2009	0.2285	22.092	192,540
2	8/8/2009	0.2277	23.152	203,064
2	8/9/2009	0.2445	22.201	182,293
2	8/10/2009	0.2472	25.346	204,973
2	8/11/2009	0.2256	22.964	203,497
2	8/12/2009	0.2961	29.01	192,204
2	8/13/2009	0.2277	21.492	188,631
2	8/14/2009	0.2335	23.534	201,382

2	8/15/2009	0.2299	21.944	191,080
2	8/16/2009	0.2366	20.663	179,765
2	8/17/2009	0.2187	21.87	200,005
2	8/18/2009	0.2978	28.635	191,809
2	8/19/2009	0.2924	27.803	189,161
2	8/20/2009	0.2888	26.9	185,739
2	8/21/2009	0.2437	21.693	178,823
2	8/22/2009	0.2332	21.642	186,341
2	8/23/2009	0.2612	19.258	159,475
2	8/24/2009	0.2303	20.179	176,997
2	8/25/2009	0.3071	28.576	186,272
2	8/26/2009	0.2597	24.244	186,079
2	8/27/2009	0.3139	30.067	190,691
2	8/28/2009	0.3126	31.529	201,669
2	8/29/2009	0.3215	31.495	195,088
2	8/30/2009	0.3267	27.579	169,222
2	8/31/2009	0.3178	29.264	183,648
2	9/1/2009	0.3099	27.268	175,096
2	9/2/2009	0.3059	28.038	181,422
2	9/3/2009	0.3375	32.789	193,031
2	9/4/2009	0.3618	36.842	203,599
2	9/5/2009	0.3384	33.023	194,479
2	9/6/2009	0.3513	29.848	169,190
2	9/7/2009	0.3366	29.943	172,742
2	9/8/2009	0.3393	32.53	188,604
2	9/9/2009	0.3634	36.179	198,949
2	9/10/2009	0.3643	36.752	201,548
2	9/11/2009	0.3347	32.879	196,345
2	9/12/2009	0.3207	30.37	188,358
2	9/13/2009	0.3158	25.212	157,901
2	9/14/2009	0.3433	32.589	189,217
2	9/15/2009	0.3474	35.384	203,659
2	9/16/2009	0.3135	30.582	195,154
2	9/17/2009	0.278	28.479	205,009
2	9/18/2009	0.2556	26.107	204,203
2	9/19/2009	0.2477	24.919	200,940
2	9/20/2009	0.24	20.354	179,055
2	9/21/2009	0.2965	29.334	197,473
2	9/22/2009	0.2865	24.363	169,762
2	9/23/2009	0.3193	31.254	194,834
2	9/24/2009	0.2957	29.356	198,015
2	9/25/2009	0.3429	32.891	190,096
2	9/26/2009	0.2707	24.502	181,353
2	9/27/2009	0.3319	29.016	173,398
2	9/28/2009	0.3338	31.934	190,619
2	9/29/2009	0.3264	30.063	181,892
2	9/30/2009	0.3341	31.157	185,729

2	10/1/2009	0.337	33.527	198,295
2	10/2/2009	0.3071	29.155	189,928
2	10/3/2009	0.3392	34.386	202,442
2	10/4/2009	0.3227	28.311	174,891
2	10/5/2009	0.3143	30.416	192,620
2	10/6/2009	0.2634	26.18	198,787
2	10/7/2009	0.2722	27.582	202,631
2	10/8/2009	0.2904	30.102	207,317
2	10/9/2009	0.3225	32.316	200,214
2	10/10/2009	0.3102	31.064	200,417
2	10/11/2009	0.2866	25.449	179,828
2	10/12/2009	0.3364	34.524	205,186
2	10/13/2009	0.3295	33.467	202,938
2	10/14/2009	0.2984	28.168	188,546
2	10/15/2009	0.3007	30.132	200,178
2	10/16/2009	0.2585	24.37	189,105
2	10/17/2009	0.2405	23.248	193,325
2	10/18/2009	0.2327	19.852	172,447
2	10/19/2009	0.2583	21.54	176,853
2	10/20/2009	0.3089	30.936	200,414
2	10/21/2009	0.331	31.573	189,942
2	10/22/2009	0.3215	32.427	201,492
2	10/23/2009	0.3254	31.777	195,004
2	10/24/2009	0.3237	30.929	190,847
2	10/25/2009	0.3014	24.939	173,417
2	10/26/2009	0.2904	28.241	193,625
2	10/27/2009	0.2895	27.138	187,182
2	10/28/2009	0.2762	25.385	183,112
2	10/29/2009	0.3016	24.228	149,851
2	10/30/2009	0.276	24.937	179,381
2	10/31/2009	0.3163	29.015	183,175
2	11/1/2009	0.3	24.027	160,652
2	11/2/2009	0.2995	28.419	189,147
2	11/3/2009	0.2779	26.764	191,721
2	11/4/2009	0.3273	32.177	196,367
2	11/5/2009	0.3008	28.209	187,854
2	11/6/2009	0.2773	26.957	194,014
2	11/7/2009	0.239	24.316	203,639
2	11/8/2009	0.2415	20.624	179,056
2	11/9/2009	0.2334	22.196	191,275
2	11/10/2009	0.274	25.86	188,887
2	11/11/2009	0.2899	25.937	177,459
2	11/12/2009	0.2822	26.204	185,163
2	11/13/2009	0.3457	33.076	191,030
2	11/14/2009	0.308	26.008	167,792
2	11/15/2009	0.2969	22.156	154,028
2	11/16/2009	0.303	28.564	186,117

2	11/17/2009	0.2463	21.708	176,444
2	11/18/2009	0.2287	20.859	182,735
2	11/19/2009	0.257	23.372	182,126
2	11/20/2009	0.3081	29.036	188,264
2	11/21/2009	0.3112	31.302	200,799
2	11/22/2009	0.2751	24.259	182,490
2	11/23/2009	0.2678	25.736	190,654
2	11/24/2009	0.283	23.623	176,602
2	11/25/2009	0.2725	27.097	198,807
2	11/26/2009	0.2737	25.751	186,850
2	11/27/2009	0.2691	24.821	182,788
2	11/28/2009	0.2781	27.448	197,275
2	11/29/2009	0.2995	26.176	176,650
2	11/30/2009	0.2893	27.559	188,729
2	12/1/2009	0.263	25.754	195,438
2	12/2/2009	0.2288	22.158	193,764
2	12/3/2009	0.2292	22.967	200,612
2	12/4/2009	0.2789	28.516	204,516
2	12/5/2009	0.3279	33.185	202,289
2	12/6/2009	0.3362	30.336	181,762
2	12/7/2009	0.2911	23.975	163,918
2	12/8/2009	0.3119	13.806	89,495
2	12/12/2009	0.1133	2.242	17,812
2	12/13/2009	0.3005	9.515	64,247
2	12/15/2009	0.0715	0.495	7,631
2	12/16/2009	0.3058	13.259	87,248
2	12/17/2009	0.2774	24.817	179,647
2	12/18/2009	0.2795	23.795	170,154
2	12/19/2009	0.2925	26.9	183,803
2	12/20/2009	0.3163	26.804	169,918
2	12/21/2009	0.3035	27.058	176,287
2	12/22/2009	0.3173	29.349	183,895
2	12/23/2009	0.3085	28.641	184,277
2	12/24/2009	0.3026	23.362	151,431
2	12/25/2009	0.2614	20.029	138,839
2	12/26/2009	0.2884	26.201	181,269
2	12/27/2009	0.3037	25.434	172,918
2	12/28/2009	0.2686	25.538	190,783
2	12/29/2009	0.2632	24.618	187,058
2	12/30/2009	0.2595	24.177	185,973
2	12/31/2009	0.2488	20.416	164,415
2	1/1/2010	0.2521	21.984	175,045
2	1/2/2010	0.2541	25.184	198,140
2	1/3/2010	0.2991	26.232	177,269
2	1/4/2010	0.3008	29.406	195,488
2	1/5/2010	0.3034	29.976	197,637
2	1/6/2010	0.2983	23.951	161,388

2	1/7/2010	0.2696	23.191	171,608
2	1/8/2010	0.267	27.171	203,605
2	1/9/2010	0.259	24.768	190,624
2	1/10/2010	0.28	23.223	174,232
2	1/11/2010	0.2847	26.609	186,798
2	1/12/2010	0.2849	12.514	87,786
2	1/13/2010	0.0186	0.024	2,204
2	1/14/2010	0.2851	23.986	147,505
2	1/15/2010	0.3113	31.803	204,470
2	1/16/2010	0.2878	28.004	194,510
2	1/17/2010	0.3285	26.02	158,205
2	1/18/2010	0.3239	28.176	173,134
2	1/19/2010	0.3114	27.115	171,179
2	1/20/2010	0.2508	20.844	166,137
2	1/21/2010	0.2464	21.427	175,286
2	1/22/2010	0.2232	19.947	179,534
2	1/23/2010	0.2739	23.923	172,387
2	1/24/2010	0.2533	19.566	159,630
2	1/25/2010	0.23	21.699	188,704
2	1/26/2010	0.2524	24.197	190,859
2	1/27/2010	0.2611	22.576	171,951
2	1/28/2010	0.3136	26.415	167,979
2	1/29/2010	0.274	23.494	171,604
2	1/30/2010	0.2962	26.224	177,073
2	1/31/2010	0.2905	22.917	157,574
2	2/1/2010	0.3446	29.991	172,425
2	2/2/2010	0.3399	27.803	162,876
2	2/3/2010	0.3475	32.646	187,540
2	2/4/2010	0.366	34.608	189,024
2	2/5/2010	0.3118	26.923	172,586
2	2/6/2010	0.3215	31.463	195,644
2	2/7/2010	0.2856	23.847	171,558
2	2/8/2010	0.2714	26.051	191,688
2	2/9/2010	0.2904	22.913	161,523
2	2/10/2010	0.274	25.86	188,792
2	2/11/2010	0.3164	29.867	187,058
2	2/12/2010	0.3386	32.637	192,683
2	2/13/2010	0.3157	29.228	184,452
2	2/14/2010	0.3246	27.164	168,702
2	2/15/2010	0.3329	33.142	199,022
2	2/16/2010	0.3281	30.89	187,869
2	2/17/2010	0.3458	32.105	184,900
2	2/18/2010	0.3348	30.135	178,528
2	2/19/2010	0.2944	26.965	181,186
2	2/20/2010	0.2753	26.523	192,646
2	2/21/2010	0.2781	22.728	167,967
2	2/22/2010	0.3088	26.762	171,561

2	2/23/2010	0.2846	25.187	176,544
2	2/24/2010	0.2874	25.997	180,771
2	2/25/2010	0.2931	26.44	180,272
2	2/26/2010	0.2967	27.438	184,193
2	2/27/2010	0.289	27.136	187,376
2	2/28/2010	0.3167	25.16	164,061
2	3/1/2010	0.299	22.904	157,411
2	3/2/2010	0.314	30.757	195,772
2	3/3/2010	0.3001	26.325	174,761
2	3/4/2010	0.368	32.709	176,014
2	3/5/2010	0.375	34.798	184,149
2	3/6/2010	0.3696	34.14	183,305
2	3/7/2010	0.3727	34.272	182,926
2	3/8/2010	0.3644	35.184	192,521
2	3/9/2010	0.3495	33.952	193,746
2	3/10/2010	0.3603	36.566	202,397
2	3/11/2010	0.3514	34.602	196,089
2	3/12/2010	0.3642	34.605	189,238
2	3/13/2010	0.3768	35.512	187,053
2	3/14/2010	0.3635	31.076	171,359
2	3/15/2010	0.3218	29.648	183,534
2	3/16/2010	0.3101	28.696	184,617
2	3/17/2010	0.3079	29.313	190,207
2	3/18/2010	0.3283	32.476	197,363
2	3/19/2010	0.3117	30.682	196,351
2	3/20/2010	0.302	26.599	176,023
2	3/21/2010	0.3317	29.287	179,193
2	3/22/2010	0.3054	28.434	185,702
2	3/23/2010	0.2925	24.976	170,091
2	3/24/2010	0.3304	32.319	193,083
2	3/25/2010	0.3379	32.485	189,060
2	3/26/2010	0.3578	35.405	197,427
2	3/27/2010	0.373	37.857	203,107
2	3/28/2010	0.3594	31.488	175,683
2	3/29/2010	0.3452	33.909	196,164
2	3/30/2010	0.3747	36.331	193,829
2	3/31/2010	0.335	32.242	191,293
2	4/1/2010	0.3479	33.54	191,858
2	4/2/2010	0.3054	25.083	164,350
2	4/21/2010	0.0104	0.009	1,248
2	4/22/2010	0.1424	5.172	47,139
2	4/23/2010	0.2579	23.589	182,271
2	4/24/2010	0.2622	23.872	182,387
2	4/25/2010	0.3231	23.56	154,666
2	4/26/2010	0.306	29.095	190,300
2	4/27/2010	0.3617	33.912	187,710
2	4/28/2010	0.3753	34.644	183,603

2	4/29/2010	0.3645	32.248	176,285
2	4/30/2010	0.3723	36.861	197,950
2	5/1/2010	0.367	37.547	204,578
2	5/2/2010	0.3828	35.725	187,772
2	5/3/2010	0.3332	33.052	198,238
2	5/4/2010	0.3265	30.152	183,692
2	5/5/2010	0.2584	22.273	172,845
2	5/6/2010	0.2874	26.371	183,523
2	5/7/2010	0.3903	40.035	205,043
2	5/8/2010	0.4003	39.405	198,799
2	5/9/2010	0.4328	35.521	170,135
2	5/10/2010	0.3978	39.861	200,328
2	5/11/2010	0.3931	40.6	206,565
2	5/12/2010	0.388	40.227	207,331
2	5/13/2010	0.4002	41.74	208,549
2	5/14/2010	0.4039	42.329	209,606
2	5/15/2010	0.4003	41.404	206,779
2	5/16/2010	0.3858	34.968	181,387
2	5/17/2010	0.359	35.109	194,245
2	5/18/2010	0.3375	32.519	191,826
2	5/19/2010	0.3555	32.992	184,593
2	5/20/2010	0.3539	23.745	141,069
2	5/21/2010	0.266	24.74	185,979
2	5/22/2010	0.2758	24.289	177,848
2	5/23/2010	0.3413	30.208	175,857
2	5/24/2010	0.3102	28.437	182,297
2	5/25/2010	0.3129	28.355	181,153
2	5/26/2010	0.309	26.721	173,220
2	5/27/2010	0.307	29.872	193,938
2	5/28/2010	0.2945	25.802	172,520
2	5/29/2010	0.2803	24.142	174,728
2	5/30/2010	0.3133	24.148	162,494
2	5/31/2010	0.3765	34.825	186,096
2	6/1/2010	0.3768	37.764	199,921
2	6/2/2010	0.373	38.857	208,101
2	6/3/2010	0.3377	33.463	197,657
2	6/4/2010	0.3548	37.292	210,092
2	6/5/2010	0.3643	37.882	207,525
2	6/6/2010	0.3784	36.735	190,765
2	6/7/2010	0.3485	33.179	186,705
2	6/8/2010	0.392	40.222	205,035
2	6/9/2010	0.3822	38.475	200,887
2	6/10/2010	0.3068	30.981	200,751
2	6/11/2010	0.2801	28.255	201,667
2	6/12/2010	0.2662	26.587	199,525
2	6/13/2010	0.2632	23.522	178,654
2	6/14/2010	0.3279	31.576	192,221

2	6/15/2010	0.4133	41.545	200,266
2	6/16/2010	0.4036	41.298	204,473
2	6/17/2010	0.3988	40.592	203,371
2	6/18/2010	0.3715	37.442	201,230
2	6/19/2010	0.3702	37.421	201,635
2	6/20/2010	0.3685	34.684	181,864
2	6/21/2010	0.3697	38.138	206,264
2	6/22/2010	0.3138	29.065	182,869
2	6/23/2010	0.3401	32.751	191,169
2	6/24/2010	0.354	35.952	203,054
2	6/25/2010	0.362	36.045	198,253
2	6/26/2010	0.3605	35.497	195,790
2	6/27/2010	0.358	31.223	173,774
2	6/28/2010	0.3546	35.884	202,169
2	6/29/2010	0.346	33.691	193,606
2	6/30/2010	0.3413	33.914	197,055
2	7/1/2010	0.3533	36.572	206,953
2	7/2/2010	0.3557	36.588	205,608
2	7/3/2010	0.3384	32.9	192,412
2	7/4/2010	0.3551	14.261	80,752
2	7/6/2010	0.1452	5.573	49,282
2	7/7/2010	0.2467	17.715	140,569
2	7/10/2010	0.108	3.371	35,086
2	7/11/2010	0.235	22.931	194,447
2	7/12/2010	0.2325	22.063	188,786
2	7/13/2010	0.2195	19.448	175,188
2	7/14/2010	0.2428	23.049	188,608
2	7/15/2010	0.3083	30.652	198,278
2	7/16/2010	0.326	30.626	187,183
2	7/17/2010	0.3212	29.628	182,888
2	7/18/2010	0.3038	25.898	168,068
2	7/19/2010	0.2688	25.087	186,290
2	7/20/2010	0.279	25.228	179,195
2	7/21/2010	0.2851	26.858	187,148
2	7/22/2010	0.2703	25.008	182,559
2	7/23/2010	0.2768	26.549	190,507
2	7/24/2010	0.2814	26.978	189,979
2	7/25/2010	0.3176	27.256	170,903
2	7/26/2010	0.3116	31.933	204,884
2	7/27/2010	0.2922	26.244	177,889
2	7/28/2010	0.3106	26.435	168,005
2	7/29/2010	0.3374	32.237	190,341
2	7/30/2010	0.3345	32.409	192,843
2	7/31/2010	0.3568	35.895	200,721
2	8/1/2010	0.3287	30	181,805
2	8/2/2010	0.3021	27.242	165,631
2	8/3/2010	0.0843	3.155	34,642

2	8/4/2010	0.2788	23.472	165,844
2	8/5/2010	0.288	24.484	169,998
2	8/6/2010	0.3184	30.386	188,776
2	8/7/2010	0.3336	33.039	197,750
2	8/8/2010	0.3155	29.241	181,162
2	8/9/2010	0.2735	24.581	173,678
2	8/10/2010	0.2764	26.072	187,917
2	8/11/2010	0.292	21.984	148,836
2	8/12/2010	0.2346	21.782	184,976
2	8/13/2010	0.2312	21.354	183,762
2	8/14/2010	0.2738	25.002	180,481
2	8/15/2010	0.3087	28.549	181,951
2	8/16/2010	0.268	23.016	166,550
2	8/17/2010	0.2336	19.862	168,430
2	8/18/2010	0.2405	20.847	170,012
2	8/19/2010	0.2278	21.202	184,826
2	8/20/2010	0.2172	19.364	177,073
2	8/21/2010	0.2313	20.219	175,695
2	8/22/2010	0.3024	22.011	151,000
2	8/23/2010	0.3017	23.994	162,738
2	8/24/2010	0.3201	29.647	183,312
2	8/25/2010	0.3027	29.621	194,079
2	8/26/2010	0.2993	13.546	93,683
2	8/28/2010	0.0992	1.178	9,671
2	8/29/2010	0.2742	25.988	187,043
2	8/30/2010	0.3024	31.544	208,567
2	8/31/2010	0.2914	29.6	202,961
2	9/1/2010	0.3032	31.274	206,243
2	9/2/2010	0.2655	26.697	200,547
2	9/3/2010	0.2697	25.059	186,800
2	9/4/2010	0.2585	22.862	176,069
2	9/5/2010	0.331	26.176	157,180
2	9/6/2010	0.312	28.411	175,000
2	9/7/2010	0.3131	31.378	200,025
2	9/8/2010	0.3125	30.693	195,640
2	9/9/2010	0.3145	30.443	192,209
2	9/10/2010	0.3163	31.898	201,819
2	9/11/2010	0.2995	31.21	208,424
2	9/12/2010	0.2738	24.756	180,088
2	9/13/2010	0.2593	23.663	180,788
2	9/14/2010	0.2643	24.632	183,553
2	9/15/2010	0.2785	26.015	184,117
2	9/16/2010	0.2548	24.886	194,499
2	9/17/2010	0.2407	23.854	197,457
2	9/18/2010	0.2501	24.501	195,124
2	9/19/2010	0.2547	20.716	165,500
2	9/20/2010	0.28	26.703	189,739

2	9/21/2010	0.3073	30.549	197,237
2	9/22/2010	0.3044	31.192	204,795
2	9/23/2010	0.2878	29.327	203,673
2	9/24/2010	0.2917	29.842	204,519
2	9/25/2010	0.3368	34.531	205,023
2	9/26/2010	0.3225	25.374	157,556
2	9/27/2010	0.343	30.288	174,395
2	9/28/2010	0.3529	33.819	189,660
2	9/29/2010	0.337	31.985	188,700
2	9/30/2010	0.3067	29.497	190,706
2	10/1/2010	0.3061	26.78	173,646
2	12/1/2010	0.045	0.104	4,636
2	12/2/2010	0.0236	0.135	9,467
2	12/3/2010	0.0877	1.465	18,170
2	12/4/2010	0.104	2.504	23,515
2	12/5/2010	0.2113	6.47	69,803
2	12/6/2010	0.0967	2.243	20,772
2	12/7/2010	0.2328	19.758	169,934
2	12/8/2010	0.2653	22.339	170,105
2	12/9/2010	0.2912	26.479	182,383
2	12/10/2010	0.3654	33.078	180,526
2	12/11/2010	0.3696	32.651	175,081
2	12/12/2010	0.3963	34.441	175,418
2	12/13/2010	0.399	37.477	187,689
2	12/14/2010	0.3696	35.364	191,113
2	12/15/2010	0.336	30.552	177,027
2	12/16/2010	0.3313	29.197	173,761
2	12/17/2010	0.2907	26.929	186,977
2	12/18/2010	0.2787	24.665	179,379
2	12/19/2010	0.3178	26.705	168,255
2	12/20/2010	0.349	33.694	192,951
2	12/21/2010	0.3601	32.432	178,474
2	12/22/2010	0.3515	30.947	175,259
2	12/23/2010	0.351	32.509	184,333
2	12/24/2010	0.2968	22.214	134,210
2	12/25/2010	0.3695	28.806	155,197
2	12/26/2010	0.3838	31.738	167,463
2	12/27/2010	0.3962	33.913	172,104
2	12/28/2010	0.3877	32.717	169,848
2	12/29/2010	0.374	32.493	175,121
2	12/30/2010	0.3763	17.001	92,260
2	1/1/2011	0.1571	10.258	72,888
2	1/2/2011	0.3065	24.754	159,372
2	1/3/2011	0.3377	31.976	188,868
2	1/4/2011	0.3243	29	178,447
2	1/5/2011	0.3359	31.322	186,552
2	1/6/2011	0.3528	32.887	186,140

2	1/7/2011	0.3586	33.09	184,333
2	1/8/2011	0.3365	31.695	188,497
2	1/9/2011	0.3695	32.573	178,845
2	1/10/2011	0.3815	37.065	194,270
2	1/11/2011	0.322	27.342	169,244
2	1/12/2011	0.2904	26.611	182,779
2	1/13/2011	0.329	28.225	171,284
2	1/14/2011	0.3639	29.033	157,835
2	1/15/2011	0.3727	34.019	182,470
2	1/16/2011	0.3495	29.224	167,817
2	1/17/2011	0.3616	35.227	194,763
2	1/18/2011	0.3418	31.47	183,364
2	1/19/2011	0.3505	34.12	194,647
2	1/20/2011	0.362	35.962	198,712
2	1/21/2011	0.409	38.632	188,608
2	1/22/2011	0.3447	29.003	166,832
2	1/23/2011	0.2647	20.198	156,556
2	1/24/2011	0.3425	31.143	178,516
2	1/25/2011	0.3683	35.628	193,152
2	1/26/2011	0.3587	34.163	189,917
2	1/27/2011	0.327	28.503	172,541
2	1/28/2011	0.3474	33.637	193,289
2	1/29/2011	0.2487	21.766	175,190
2	1/30/2011	0.2694	21.502	162,375
2	1/31/2011	0.2805	26.358	187,686
2	2/1/2011	0.2641	25.027	189,268
2	2/2/2011	0.2776	24.727	179,526
2	2/3/2011	0.2923	28.113	191,589
2	2/4/2011	0.3581	36.424	203,281
2	2/5/2011	0.3545	32.365	181,344
2	2/6/2011	0.3216	26.366	162,975
2	2/7/2011	0.3342	32.138	191,591
2	2/8/2011	0.3262	29.09	176,917
2	2/9/2011	0.329	27.564	167,571
2	2/10/2011	0.3225	25.494	157,562
2	2/11/2011	0.3317	29.545	176,463
2	2/12/2011	0.3191	27.466	169,020
2	2/13/2011	0.2287	16.557	134,415
2	2/14/2011	0.2986	22.494	148,370
2	2/15/2011	0.2849	19.686	139,767
2	2/16/2011	0.2948	15.505	106,012
2	2/17/2011	0.2732	14.729	111,337
2	2/18/2011	0.2881	19.392	135,793
2	2/19/2011	0.331	26.26	162,383
2	2/20/2011	0.3196	28.728	179,729
2	2/21/2011	0.3105	29.272	185,021
2	2/22/2011	0.3304	29.663	177,386

2	2/23/2011	0.3506	35.712	203,253
2	2/24/2011	0.3146	31.055	194,571
2	2/25/2011	0.2811	28.443	202,408
2	2/26/2011	0.2765	28.378	205,295
2	2/27/2011	0.2891	27.658	189,608
2	2/28/2011	0.3297	34.86	211,352
2	3/1/2011	0.3283	33.836	206,093
2	3/2/2011	0.331	34.265	206,423
2	3/3/2011	0.3394	35.523	209,307
2	3/4/2011	0.3215	30.34	188,099
2	3/5/2011	0.3319	29.637	178,607
2	3/6/2011	0.3313	27.632	169,866
2	3/7/2011	0.3144	32.563	206,953
2	3/8/2011	0.3067	32.381	211,010
2	3/9/2011	0.3152	31.182	197,610
2	3/10/2011	0.3255	30.724	188,717
2	3/11/2011	0.3295	34.078	206,650
2	3/12/2011	0.3235	34.456	213,036
2	3/13/2011	0.3058	24.608	162,616
2	3/14/2011	0.3025	30.474	199,841
2	3/15/2011	0.2844	26.545	185,436
2	3/16/2011	0.2795	25.471	181,160
2	3/17/2011	0.2815	22.485	158,614
2	3/18/2011	0.292	28.045	192,123
2	3/19/2011	0.3094	32.343	208,308
2	3/20/2011	0.3246	30.831	189,882
2	3/21/2011	0.3083	30.126	194,306
2	3/22/2011	0.3078	28.047	181,559
2	3/23/2011	0.3182	31.24	196,293
2	3/24/2011	0.3351	32.411	192,495
2	3/25/2011	0.3134	25.287	161,512
2	4/22/2011	0.0154	0.032	3,347
2	4/23/2011	0.0797	0.905	10,938
2	4/24/2011	0.2057	6.768	47,080
2	4/25/2011	0.4353	14.765	67,630
2	4/26/2011	0.4074	17.319	90,046
2	4/27/2011	0.3159	26.349	167,264
2	4/28/2011	0.3023	29.551	195,195
2	4/29/2011	0.2912	27.205	187,004
2	4/30/2011	0.2893	27.584	190,167
2	5/1/2011	0.2915	27.14	191,320
2	5/2/2011	0.3033	26.229	174,501
2	5/3/2011	0.2965	28.338	190,403
2	5/4/2011	0.2855	27.677	193,587
2	5/5/2011	0.3054	25.994	175,667
2	5/6/2011	0.3395	20.327	131,417
2	5/7/2011	0.2989	26.32	176,429

2	5/8/2011	0.2846	26.157	181,568
2	5/9/2011	0.2891	24.19	166,892
2	5/10/2011	0.297	27.609	184,996
2	5/11/2011	0.2976	24.67	165,855
2	5/12/2011	0.3067	30.139	195,742
2	5/13/2011	0.2613	18.901	143,927
2	5/14/2011	0.276	21.857	158,210
2	5/15/2011	0.2631	18.014	139,159
2	5/16/2011	0.2928	27.122	183,308
2	5/17/2011	0.2739	22.106	158,795
2	5/18/2011	0.2705	23.72	174,718
2	5/19/2011	0.2911	26.385	179,383
2	5/20/2011	0.2539	20.339	159,868
2	5/21/2011	0.2578	12.945	101,852
2	5/22/2011	0.2976	21.231	144,917
2	5/23/2011	0.2485	14.69	118,399
2	5/24/2011	0.3088	12.364	80,878
2	5/25/2011	0.2932	11.129	76,148
2	5/26/2011	0.3034	10.596	69,987
2	5/27/2011	0.2583	14.89	120,281
2	5/28/2011	0.32	16.437	111,238
2	5/29/2011	0.2447	15.595	130,302
2	5/30/2011	0.2413	20.953	170,818
2	5/31/2011	0.2467	24.483	196,530
2	6/1/2011	0.2744	27.395	196,527
2	6/2/2011	0.2744	26.665	192,143
2	6/3/2011	0.2734	28.35	206,952
2	6/4/2011	0.2702	27.107	199,470
2	6/5/2011	0.2429	14.817	122,241
2	6/6/2011	0.2496	13.002	107,680
2	6/7/2011	0.2536	21.797	167,955
2	6/8/2011	0.268	25.231	184,359
2	6/9/2011	0.2729	26.915	194,932
2	6/10/2011	0.3011	29.11	190,674
2	6/11/2011	0.2943	27.653	184,465
2	6/12/2011	0.2657	19.515	156,987
2	6/13/2011	0.2168	19.877	183,027
2	6/14/2011	0.2618	24.78	185,435
2	6/15/2011	0.2891	29.903	206,659
2	6/16/2011	0.2811	27.153	191,163
2	6/17/2011	0.2731	25.534	185,428
2	6/18/2011	0.2508	22.435	175,735
2	6/19/2011	0.2364	15.654	134,013
2	6/20/2011	0.2294	14.844	130,187
2	6/21/2011	0.2589	25.915	199,965
2	6/22/2011	0.2662	24.749	183,686
2	6/23/2011	0.261	22.766	173,460

2	6/24/2011	0.2989	27.056	177,380
2	6/25/2011	0.3237	30.516	185,524
2	6/26/2011	0.3334	30.913	182,575
2	6/27/2011	0.3429	35.861	208,930
2	6/28/2011	0.294	25.958	174,332
2	6/29/2011	0.2607	22.085	171,964
2	6/30/2011	0.2809	27.622	195,290
2	7/1/2011	0.288	28.731	198,248
2	7/2/2011	0.1999	9.025	61,606
2	7/3/2011	0.2851	28.029	195,550
2	7/4/2011	0.268	21.373	157,070
2	7/5/2011	0.288	25.499	176,014
2	7/6/2011	0.235	23.654	200,501
2	7/7/2011	0.3074	31.39	203,619
2	7/8/2011	0.3149	31.906	200,271
2	7/9/2011	0.3007	27.847	178,256
2	7/10/2011	0.3209	27.654	169,295
2	7/11/2011	0.3645	31.83	178,807
2	7/12/2011	0.2723	24.976	181,806
2	7/13/2011	0.3083	31.829	205,909
2	7/14/2011	0.2963	30.862	208,357
2	7/15/2011	0.3132	32.633	207,754
2	7/16/2011	0.3098	32.203	207,288
2	7/17/2011	0.301	28.777	190,890
2	7/18/2011	0.3318	34.52	207,540
2	7/19/2011	0.3313	33.476	198,487
2	7/20/2011	0.3009	30.804	204,046
2	7/21/2011	0.3122	31.825	202,267
2	7/22/2011	0.3216	33.074	205,062
2	7/23/2011	0.2972	30.875	207,394
2	7/24/2011	0.3365	31.384	186,061
2	7/25/2011	0.3251	31.846	193,676
2	7/26/2011	0.3286	32.634	196,129
2	7/27/2011	0.3365	34.355	201,593
2	7/28/2011	0.3529	37.867	214,033
2	7/29/2011	0.2943	26.439	174,026
2	7/30/2011	0.3167	29.456	178,259
2	7/31/2011	0.3233	30.134	183,246
2	8/1/2011	0.3192	32.162	199,254
2	8/2/2011	0.2609	25.231	192,635
2	8/3/2011	0.2618	25.831	194,914
2	8/4/2011	0.2329	24.194	207,737
2	8/5/2011	0.2261	23.17	204,342
2	8/6/2011	0.2253	23.26	206,213
2	8/7/2011	0.2264	21.331	188,936
2	8/8/2011	0.2853	29.578	206,554
2	8/9/2011	0.2811	28.673	202,776

2	8/10/2011	0.2896	29.131	199,345
2	8/11/2011	0.252	22.855	179,447
2	8/12/2011	0.2611	26.332	200,232
2	8/13/2011	0.2598	25.658	197,416
2	8/14/2011	0.2565	22.782	178,243
2	8/15/2011	0.2477	22.743	183,781
2	8/16/2011	0.2086	19.929	190,837
2	8/17/2011	0.2208	23.255	210,147
2	8/18/2011	0.2521	25.62	202,877
2	8/19/2011	0.2647	27.012	204,403
2	8/20/2011	0.2563	26.25	204,545
2	8/21/2011	0.2664	24.956	186,682
2	8/22/2011	0.2675	27.336	203,535
2	8/23/2011	0.2676	27.43	203,865
2	8/24/2011	0.2668	23.601	178,100
2	8/25/2011	0.2871	28.338	196,837
2	8/26/2011	0.2703	24.915	185,898
2	8/27/2011	0.2457	23.195	189,383
2	8/28/2011	0.2696	22.77	176,413
2	8/29/2011	0.2583	25.34	196,451
2	8/30/2011	0.2771	27.346	197,920
2	8/31/2011	0.2656	28.467	214,333
2	9/1/2011	0.2654	23.516	175,562
2	9/2/2011	0.2482	23.565	187,428
2	9/3/2011	0.2916	30.884	211,687
2	9/4/2011	0.2594	24.55	189,483
2	9/5/2011	0.2502	20.05	161,186
2	9/6/2011	0.2585	20.204	155,925
2	9/7/2011	0.2793	23.578	172,454
2	9/8/2011	0.2599	23.223	178,486
2	9/9/2011	0.2633	22.618	175,494
2	9/10/2011	0.2599	24.196	186,193
2	9/11/2011	0.2642	24.619	187,124
2	9/12/2011	0.247	22.818	184,261
2	9/13/2011	0.246	21.46	174,038
2	9/14/2011	0.2328	19.757	169,212
2	9/15/2011	0.2435	23.005	188,691
2	9/16/2011	0.2602	24.435	186,465
2	9/17/2011	0.2682	26.451	196,960
2	9/18/2011	0.3064	28.174	184,043
2	9/19/2011	0.2624	7.302	55,153
2	9/22/2011	0.134	5.352	44,509
2	9/23/2011	0.3209	31.305	192,018
2	9/24/2011	0.304	28.682	184,634
2	9/25/2011	0.3203	28.745	174,812
2	9/26/2011	0.3344	32.405	192,834
2	9/27/2011	0.3165	31.052	194,835

2	9/28/2011	0.3546	35.064	196,437
2	9/29/2011	0.3133	26.285	165,518
2	9/30/2011	0.3222	25.44	156,812
2	10/1/2011	0.318	26.529	163,164
2	10/2/2011	0.3493	26.624	153,355
2	10/3/2011	0.3246	28.623	174,058
2	10/4/2011	0.3429	29.855	177,266
2	10/5/2011	0.3263	31.736	193,368
2	10/6/2011	0.3228	31.616	194,987
2	10/7/2011	0.295	28.243	190,849
2	10/8/2011	0.3057	31.318	204,446
2	10/9/2011	0.3088	27.552	176,986
2	10/10/2011	0.329	32.957	199,629
2	10/11/2011	0.273	27.712	203,250
2	10/12/2011	0.2425	23.365	191,902
2	10/13/2011	0.2402	23.74	197,459
2	10/14/2011	0.2455	23.187	189,663
2	10/15/2011	0.3059	24.14	155,345
2	10/16/2011	0.2848	25.31	173,345
2	10/17/2011	0.2955	28.576	189,933
2	10/18/2011	0.2881	27.075	186,994
2	10/19/2011	0.2738	24.63	181,250
2	10/20/2011	0.2779	24.269	173,114
2	10/21/2011	0.2913	26.878	182,907
2	10/22/2011	0.3466	36.089	208,037
2	10/23/2011	0.2785	26.041	184,885
2	10/24/2011	0.2721	27.894	204,883
2	10/25/2011	0.2856	28.708	199,779
2	10/26/2011	0.2744	26.353	188,847
2	10/27/2011	0.2793	27.005	191,413
2	10/28/2011	0.2963	30.04	202,311
2	10/29/2011	0.2928	28.162	191,651
2	10/30/2011	0.2954	25.071	167,684
2	10/31/2011	0.3375	31.984	188,030
2	11/1/2011	0.3317	32.563	193,330
2	11/2/2011	0.3139	32.454	206,908
2	11/3/2011	0.2676	23.265	172,204
2	11/4/2011	0.2889	25.527	176,428
2	11/5/2011	0.289	24.936	172,793
2	11/6/2011	0.2969	25.477	171,359
2	11/7/2011	0.262	19.485	129,072
2	11/9/2011	0.1507	6.801	50,118
2	11/10/2011	0.2725	21.016	153,874
2	11/11/2011	0.2444	20.408	165,110
2	11/12/2011	0.3042	26.637	175,346
2	11/13/2011	0.3302	30.458	185,707
2	11/14/2011	0.2984	25.694	170,338

2	11/15/2011	0.2926	20.775	141,914
2	11/16/2011	0.3269	21.819	136,238
2	11/17/2011	0.3152	28.964	184,844
2	11/18/2011	0.3428	33.473	195,154
2	11/19/2011	0.3236	32.434	200,738
2	11/20/2011	0.3436	33.209	192,162
2	11/21/2011	0.3228	32.172	196,138
2	11/22/2011	0.3177	28.567	178,506
2	11/23/2011	0.3145	28.129	176,366
2	11/24/2011	0.3302	21.202	130,692
2	11/25/2011	0.2779	21.25	151,984
2	11/26/2011	0.2963	26.207	173,827
2	11/27/2011	0.3308	27.062	162,932
2	11/28/2011	0.3039	27.534	178,807
2	11/29/2011	0.2962	25.953	175,906
2	11/30/2011	0.3092	24.526	159,232
2	12/1/2011	0.3134	26.167	168,733
2	12/2/2011	0.2819	25.736	181,519
2	12/3/2011	0.3392	24.974	149,365
2	12/4/2011	0.2985	26.271	178,248
2	12/5/2011	0.2946	28.484	193,406
2	12/6/2011	0.289	25.317	179,603
2	12/7/2011	0.2953	21.698	149,209
2	12/8/2011	0.3079	19.546	132,742
2	12/9/2011	0.3015	21.19	147,856
2	12/10/2011	0.2896	26.812	186,436
2	12/11/2011	0.302	27.771	185,936
2	12/12/2011	0.285	23.779	166,663
2	12/13/2011	0.2806	18.117	129,960
2	12/14/2011	0.2838	19.14	134,316
2	12/15/2011	0.2949	23.489	157,149
2	12/16/2011	0.3114	29.531	190,167
2	12/17/2011	0.3121	25.9	165,930
2	12/18/2011	0.327	27.776	168,922
2	12/19/2011	0.3095	25.127	161,665
2	12/20/2011	0.2754	22.849	163,201
2	12/21/2011	0.3067	25.873	164,714
2	12/22/2011	0.3334	27.904	166,210
2	12/23/2011	0.3517	30.803	174,912
2	12/24/2011	0.3165	24.891	158,405
2	12/25/2011	0.3011	17.471	117,238
2	12/26/2011	0.305	25.869	168,332
2	12/27/2011	0.306	25.925	167,343
2	12/28/2011	0.3137	27.543	172,303
2	12/29/2011	0.2716	21.473	158,248
2	12/30/2011	0.2563	18.977	147,671
2	12/31/2011	0.2609	19.478	148,056

Max (tpd) -->	**42.329**
Max (lb/hr) -->	**3527.416667**

Note: Dates with no operation/emissions not shown

APPENDIX E

S&L NOX CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

LEGAL NOTICE

This report ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Gill Elrod Ragon Owen & Sherman, P.A. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

EPA-HQ-2018-002296

White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

CONTRIBUTORS

Prepared by:

Kristen C Bell — 5/16/2013
Kristen Bell — Date
Environmental Associate

Joy Rooney — 5/16/2013
Joy Rooney — Date
Environmental Associate

Reviewed by:

Steve Katzberger — 5/16/2013
Steve Katzberger — Date
Environmental Lead

Approved by:

S. C. McHone — 5/16/2013
Sean McHone — Date
Project Manager

ED_002110_00032338-00184

ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering. The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: Sean C. McHone Date: 5/16/2013

Seal:

STATE OF ARKANSAS
LICENSED
PROFESSIONAL ENGINEER
No. 15308
SEAN C. McHONE

S. C. McHone
5/16/2013

Issue:	Date:	Certified By:	Pages Certified:

EPA-HQ-2018-002296

1. INTRODUCTION 1
1.1. OBJECTIVE 1
1.2. UNIT DESCRIPTIONS 1
1.2.1. White Bluff - Units 1 & 2 1
1.2.2. White Bluff Auxiliary Boiler 1
1.2.3. Lake Catherine - Unit 4 1
1.3. ESTIMATE METHODOLOGY 2
1.3.1. Capital Cost Estimates 2
1.3.2. Operating and Maintenance Cost Estimates 3
1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES 3
2. WHITE BLUFF - UNITS 1 & 2 4
2.1. FUEL SWITCHING OPTIONS 4
2.1.1. Natural Gas 4
2.1.2. Propane 4
2.2. COMBUSTION CONTROLS 4
2.2.1. Low NOx Burners and Over-Fire Air 4
2.2.2. Flue Gas Recirculation (FGR) 5
2.2.3. Neural Network 5
2.3. POST COMBUSTION CONTROLS 6
2.3.1. Selective Non-Catalytic Reduction 6
2.3.2. Selective Catalytic Reduction 7
2.4. CAPITAL COSTS 8
2.5. OPERATING AND MAINTENANCE COSTS 9
3. WHITE BLUFF AUXILIARY BOILER 11
3.1. FUEL SWITCHING 11
3.2. COMBUSTION CONTROLS 11
3.2.1. Low NOx Burners + Over-Fire Air 11
3.2.2. Flue Gas Recirculation 11
3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation 11
3.2.4. Neural Network 12
3.3. POST COMBUSTION CONTROLS 12
3.3.1. Selective Non-Catalytic Reduction 12
3.3.2. Selective Catalytic Reduction 12

ED_002110_00032338-00186

EPA-HQ-2018-002296

3.4. CAPITAL COST ESTIMATES 13
3.5. OPERATING AND MAINTENANCE COST ESTIMATES 13
4. LAKE CATHERINE - UNIT 4 15
4.1. FUEL SWITCHING 15
4.2. COMBUSTION CONTROLS 15
4.2.1. Burners-Out-Of-Service 15
4.2.2. Low NOx Burners + Over-Fire Air 16
4.2.3. Flue Gas Recirculation 16
4.2.4. Water Injection 16
4.2.5. Neural Network 17
4.3. POST COMBUSTION CONTROLS 17
4.3.1. Selective Non-Catalytic Reduction 17
4.3.2. Selective Catalytic Reduction 17
4.4. CAPITAL COST ESTIMATES 18
4.5. OPERATING AND MAINTENANCE COST ESTIMATES 19
APPENDIX A: CAPITAL COST ESTIMATE 2
1. BASIS OF ESTIMATES 2
2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS 2
APPENDIX B 3
1. ESTIMATED PROJECT SCHEDULES 3
APPENDIX C 4
1. OPERATING AND MAINTENANCE COST ESTIMATES 4
APPENDIX D 5
1. BOOS AT FULL UNIT LOAD 5

ED_002110_00032338-00187

EPA-HQ-2018-002296

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

ED_002110_00032338-00188

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The "design target" NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission

rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame

temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) into the furnace at high flue gas temperatures (approximately 1600 °F – 2000 °F). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 °F – 2000 °F. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous

EPA-HQ-2018-002296

long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

ED_002110_00032338-00195

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			Unit 2		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx

from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original "high" burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated "fuel rich", lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for

the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	Controlled NOx (lb/MMBtu)	Total Installed Capital Cost (2012$)
Baseline	0.4825[1]	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	Variable O&M[1,2] Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

EPA-HQ-2018-002296

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

ED_002110_00032338-00207

Client: Entergy
Station: White Bluff/Lake Catherine
Project No.: 13027-001

Sargent & Lundy LLC

Preparer: A Hays
Date: 09/04/2012 (Rev 0)

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station.
White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as "Variable Accounts". These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10's Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
  - 31813A @ 19% of construction cost
  - 31814A @ 8% of construction cost
  - 31815A @ 8% of construction cost
  - 31816A @ 16% of construction cost
  - 31817A @ 6% of construction cost
  - 31818A @ 6% of construction cost
  - 31819A @ 8% of construction cost
  - 31820A @ 12% of construction cost
  - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
  - 31813A @ 6% of construction cost
  - 31814A @ 3% of construction cost
  - 31815A @ 2% of construction cost
  - 31816A @ 6% of construction cost
  - 31817A @ 2% of construction cost

  - 31818A @ 2% of construction cost
  - 31819A @ 2% of construction cost
  - 31820A @ 0% of construction cost
  - 31832A @ 6% of construction cost
- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

ESTIMATE NO.: 31813A2
PROJECT NO.: 13027-001
ISSUE DATE:
PREP./REV.: ADH/
APPROVED:

ENTERGY - LAKE CATHERINE
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

ESTIMATE NO.: 31814A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - LAKE CATHERINE
SCR SYSTEM - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

ESTIMATE NO.: 31815A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - LAKE CATHERINE
SNCR SYSTEM - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

ESTIMATE NO.: 31816A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

ESTIMATE NO.: 31819A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SNCR SYSTEM - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

ESTIMATE NO.: 31817A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SCR - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

ESTIMATE NO.: 31832A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

ESTIMATE NO.: 31840A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SNCR SYSTEM - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

ESTIMATE NO.: 31818A
PROJECT NO.: 13027-001
ISSUE DATE:
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SCR - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

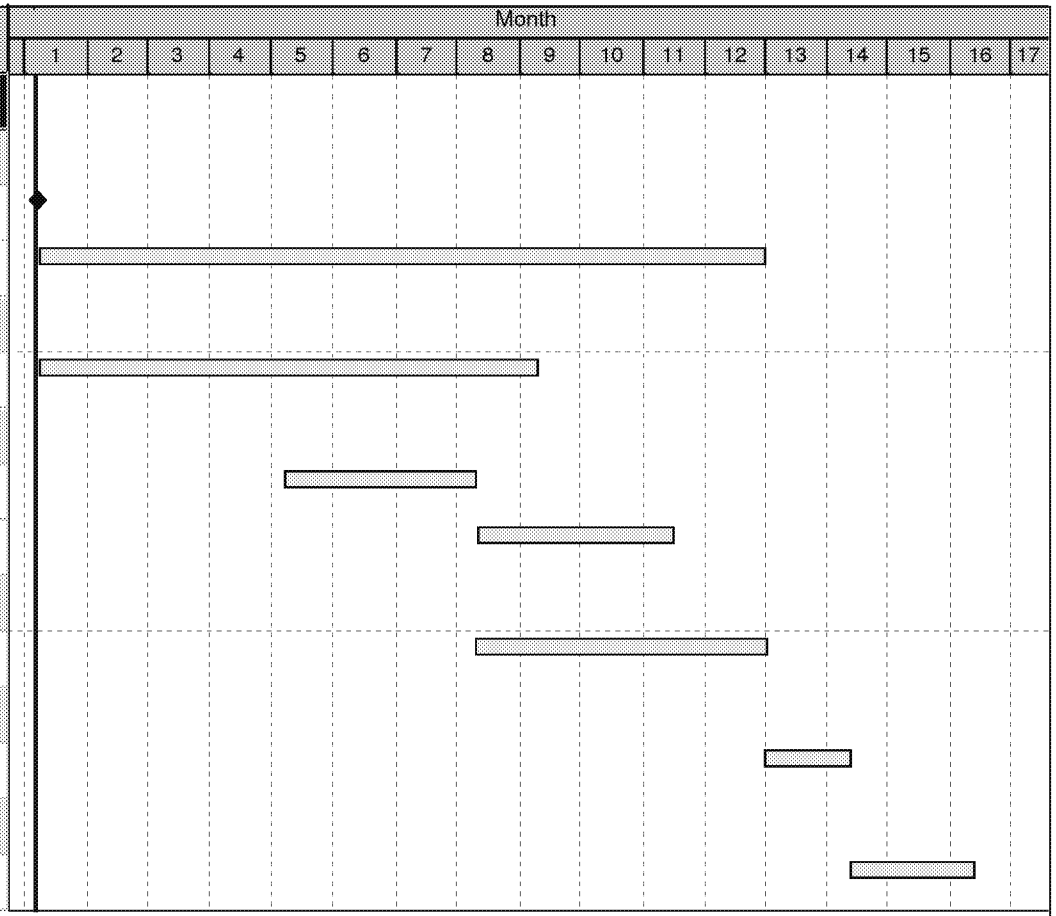
EPA-HQ-2018-002296

APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

ED_002110_00032338-00220

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		6m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		5m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

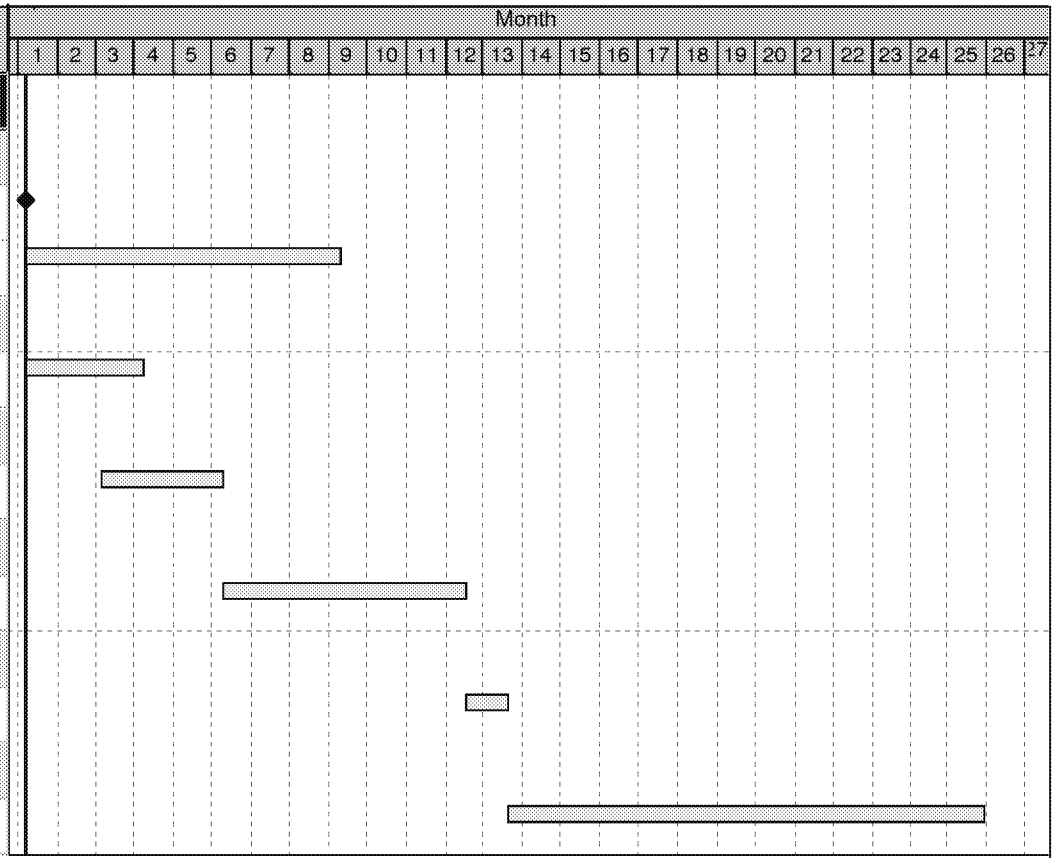


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for
Entergy Services, Inc. White Bluff and Lake Catherine
Aux Boiler Low NOx Burner/Over-Fire Air/Flue Gas Recirculation (LNB/OFA/FGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Neural Network		24m
Permitting		8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
Engineering		3m
A1020	Engineering	3m
Procurement of Major Equipment		3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		12m
A1060	Commissioning & Start-Up	12m

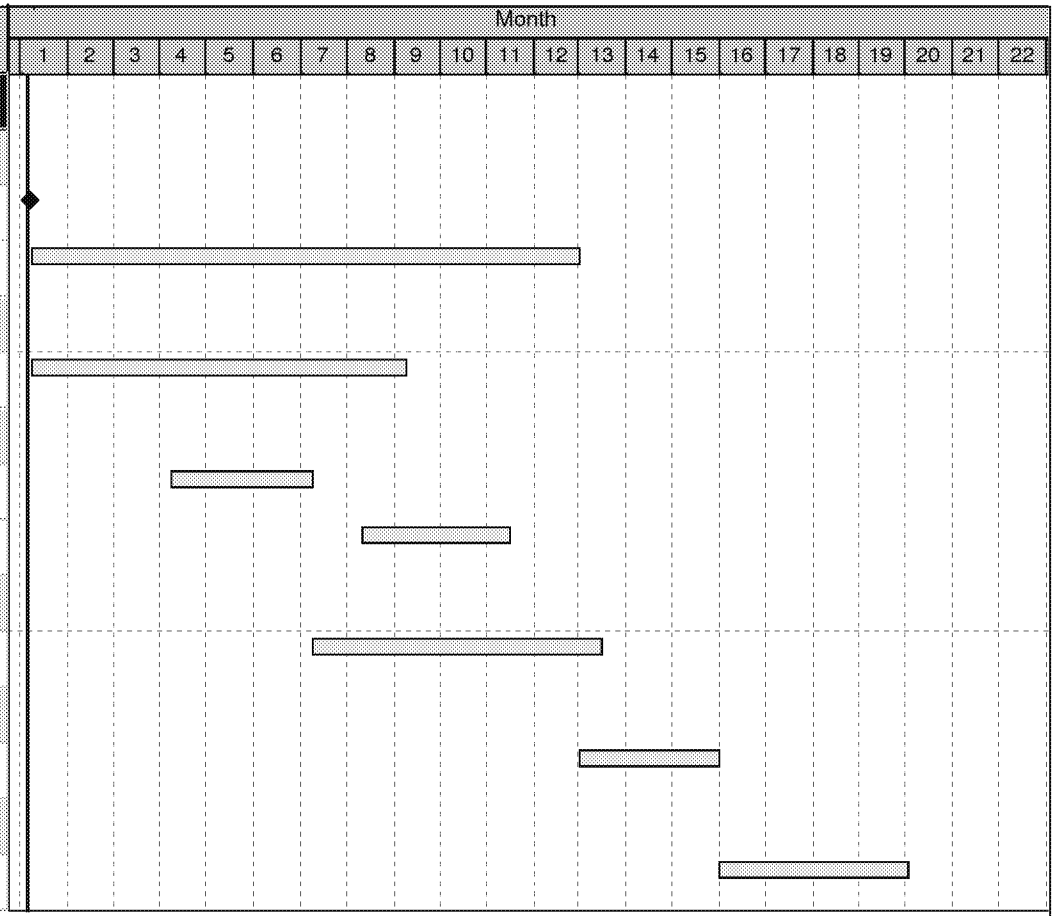


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Neural Network

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Low NOx Burners/Over ...		19m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
Installation		3m
A1050	Installation	3m
Commissioning & Start-Up		4m
A1060	Commissioning & Start-Up	4m

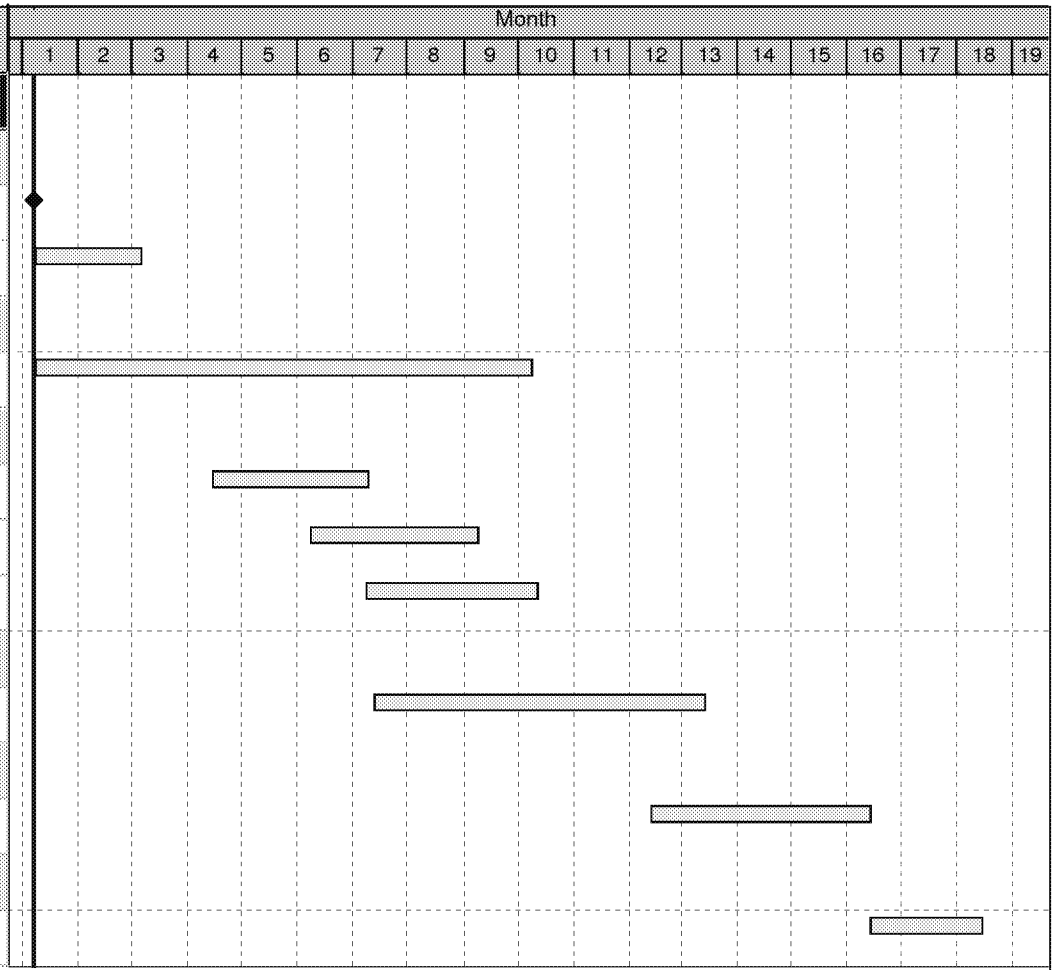


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Low NOx Burners/Over-Fire Air (LNB/OFA)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Induced Flue Gas Recir...		17m
Permitting		2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
Engineering		9m
A1020	BOP Engineering	9m
Procurement of Major Equipment		6m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
Installation		4m
A1050	Installation	4m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

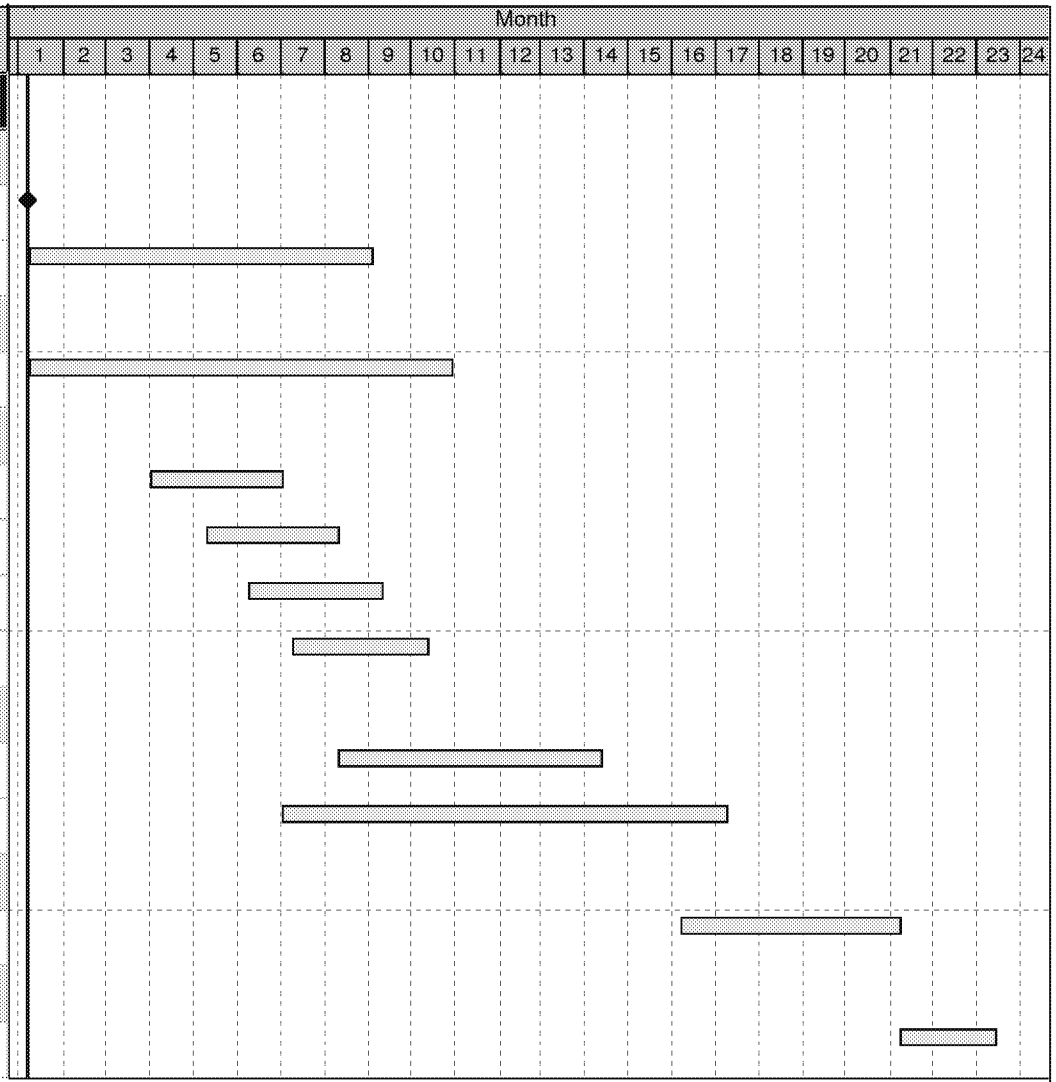


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Induced Flue Gas Recirculation (IFGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Flue Gas Recirculation ...		22m
Permitting		8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
Engineering		10m
A1020	BOP Engineering	10m
Procurement of Major Equipment		6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
Installation		5m
A1050	Installation	5m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

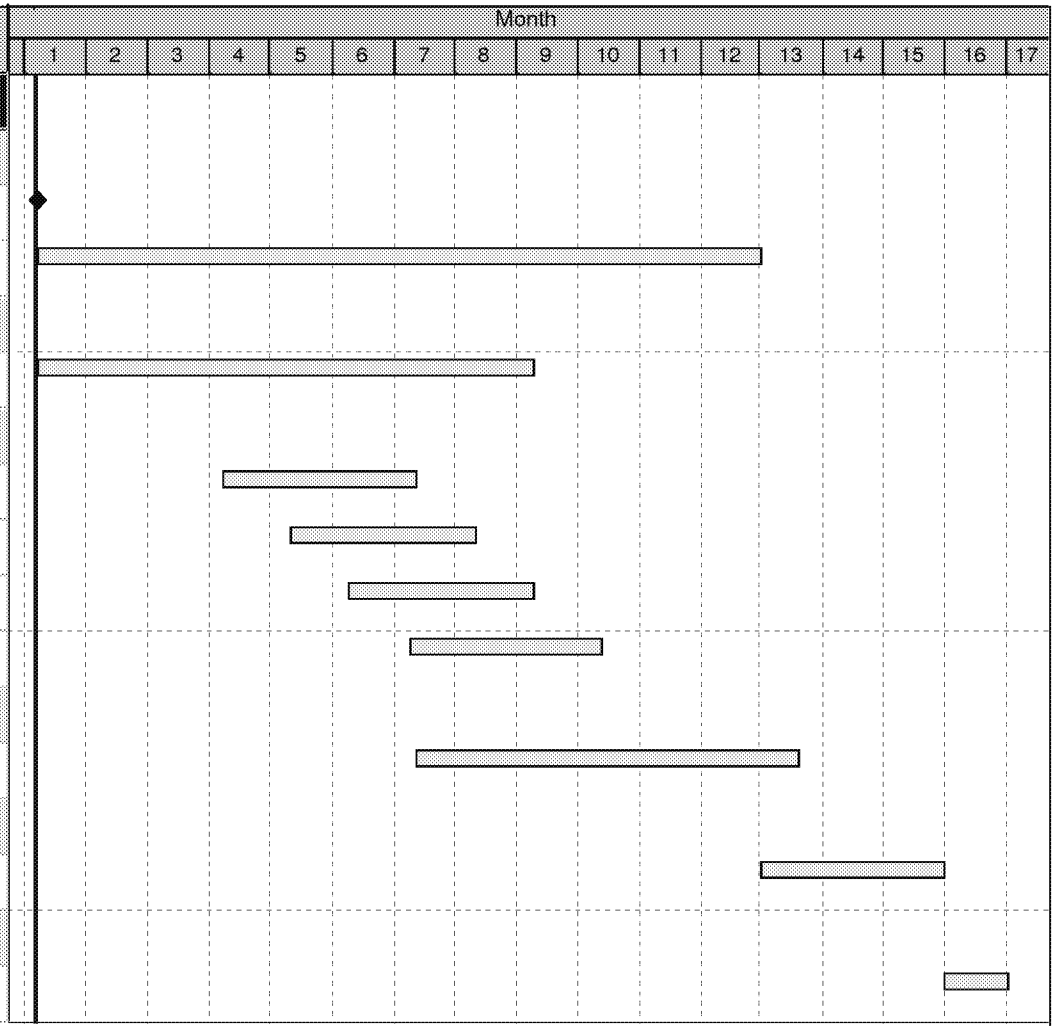


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Flue Gas Recirculation (FGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Selective Non-Catalytic ...		16m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	BOP Engineering	8m
Procurement of Major Equipment		6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
Installation		3m
A1050	Installation	3m
Commissioning & Start-Up		1m
A1060	Commissioning & Start-Up	1m

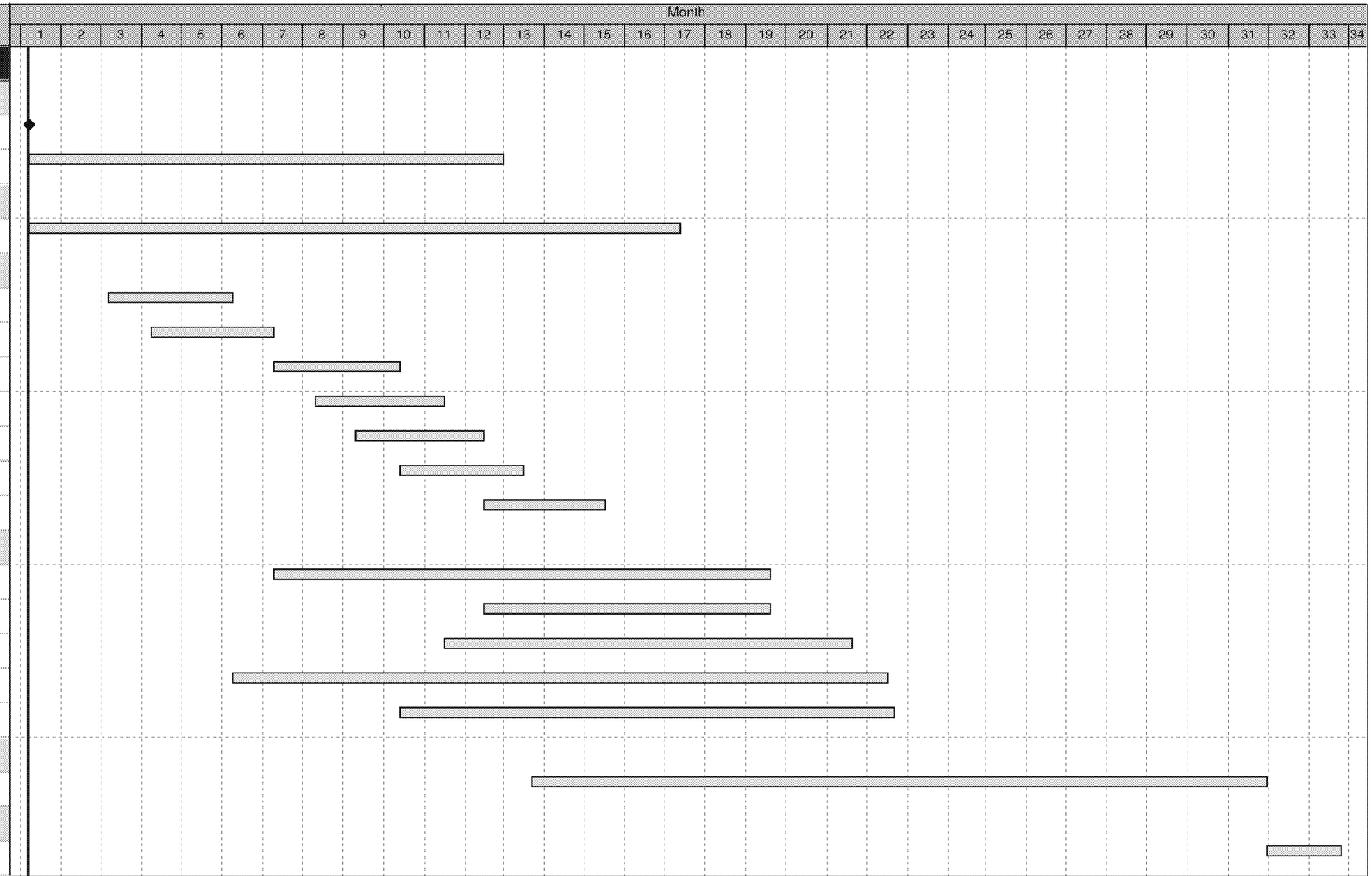


Run Date: 09-14-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Non-Catalytic Reduction (SNCR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Selective Catalytic Red...		32m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		16m
A1020	BOP Engineering	16m
Procurement of Major Equipment		12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
Installation		18m
A1050	Installation	18m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m



Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Catalytic Reduction (SCR)

Sargent & Lundy

EPA-HQ-2018-002296

APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

ED_002110_00032338-00228

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit Name White Bluff 2

Unit Data	
Size (Gross kW)	844,000
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0
Avg. Heat Rate (Btu/kwh)	10,604.3
Aux. Power (kw)	-
Est. Capacity Factor (%)	76.00
Boiler Type	T/F
Boiler Eff. (%)	84
Estimated NOx, tons/day Max	**31.833**
Emission Limit, tons	-
NOx Sales/Buy rate, $/ton	-
Fuel -	PRB
Seasonal Days	153
Basis	0
Analysis - Enter "0" for Annual and 1 for Seasonal	
CF For Variable O&M	76.00

Reagent Costs	
Aq.Ammonia $/t	$700
An.Ammonia $/t	$400
Urea $/t	$350
N/F-T Urea $/t	$618
Coal Cost, $/Mbtu	2.650
Water Cost, $/1000 gal (3)	2
Electricity, $/MWh	41.50

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit name Lake Catherine Unit 4

Unit Data	
Size (Gross kW)	558,000
Average NOx Emission Rate (lb/MMBtu)	0.4825
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0
Avg. Heat Rate (Btu/kwh)	10,483.9
Aux. Power (kw)	-
Est. Capacity Factor (%)	10.00
Boiler Type	T/F
Boiler Eff. (%)	82
Estimated NOx, tons/day Max	3.387
Emission Limit, tons	-
NOx Sales/Buy rate, $/ton	2500.0
Fuel	Gas
Seasonal Days	153
Basis	0
Analysis - Enter "0" for Annual and 1 for Seasonal	
CF For Variable O&M	10.00

Reagent Costs	
Aq.Ammonia $/t	$700
An.Ammonia $/t	$400
Urea $/t	$350
N/F-T Urea $/t	$618
Gas Cost, $/MBtu	4.900
Water Cost, $/1000 gal (3)	2
Electricity, $/MWh	41.50

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost		
							Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

EPA-HQ-2018-002296

APPENDIX D

1. BOOS AT FULL UNIT LOAD

ED_002110_00032338-00232

To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

****
This e-mail and any of its attachments may contain ETEC Inc. proprietary information, which is privileged, confidential, or subject to copyright belonging to the ETEC Inc. This e-mail is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this e-mail, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this e-mail is strictly prohibited and may be unlawful. If you have received this e-mail in error, please notify the sender immediately and permanently delete the original and any copy of this e-mail and any printout. Thank You.

********** BOOS for NOx Control.pdf

Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction

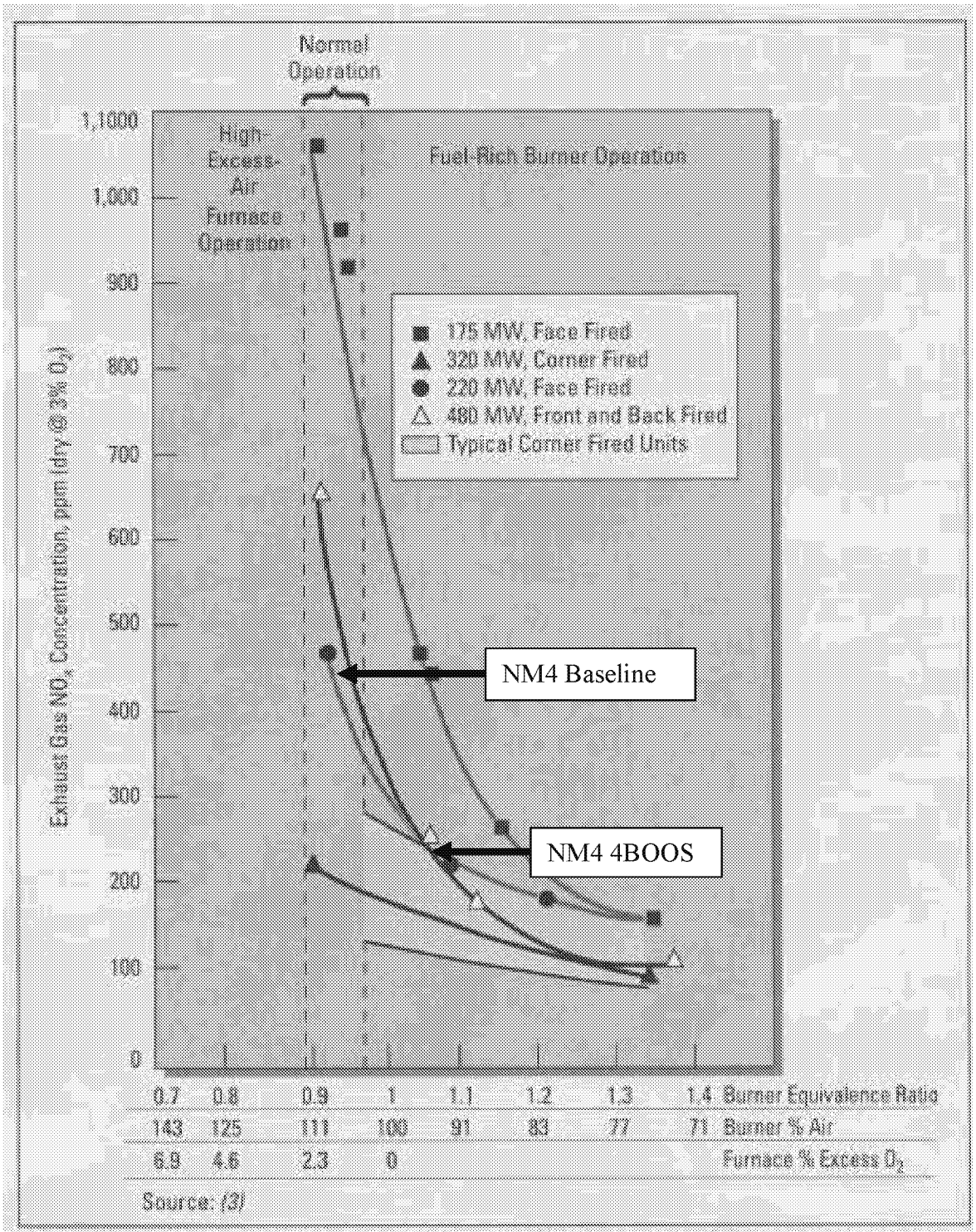


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

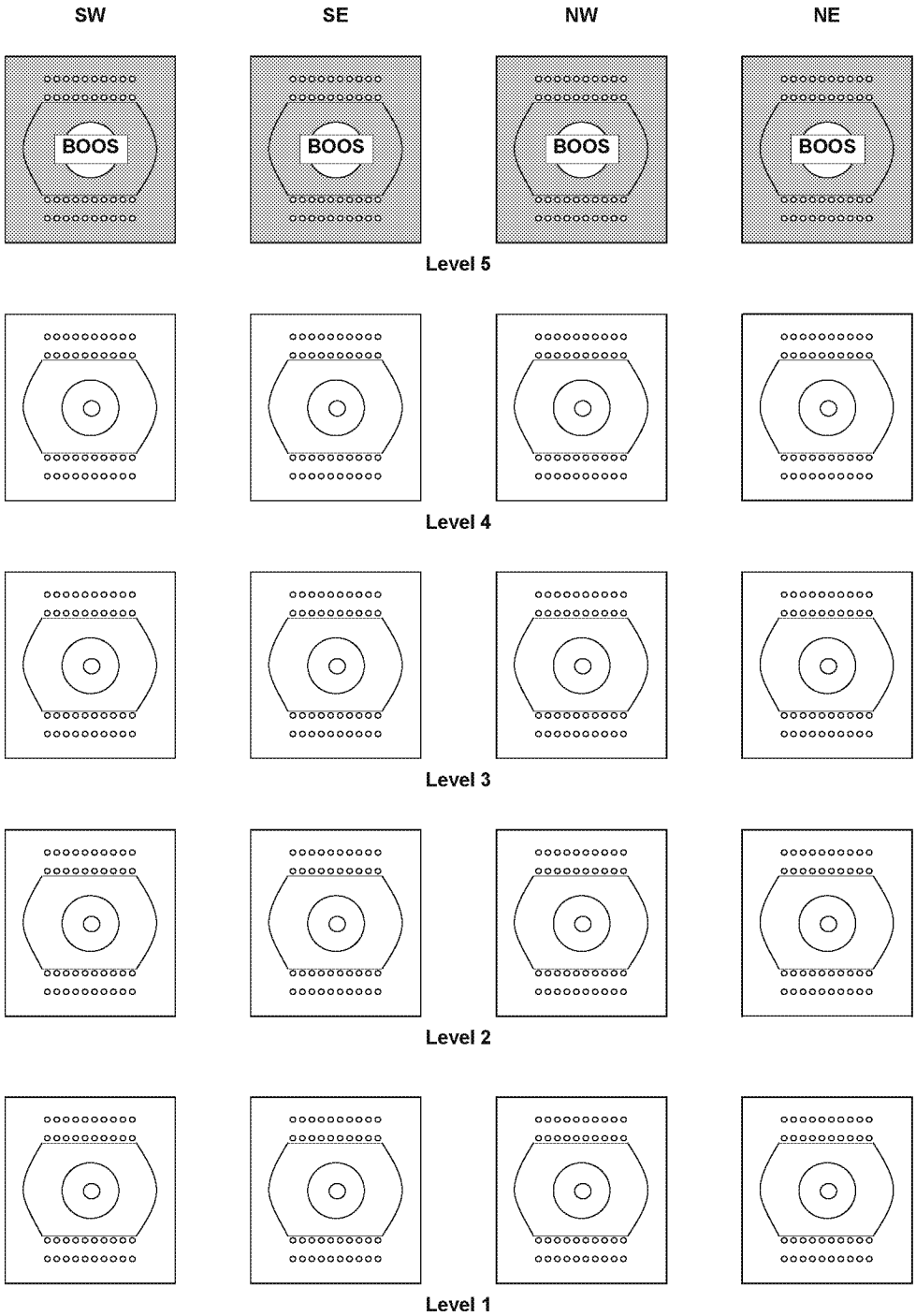


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

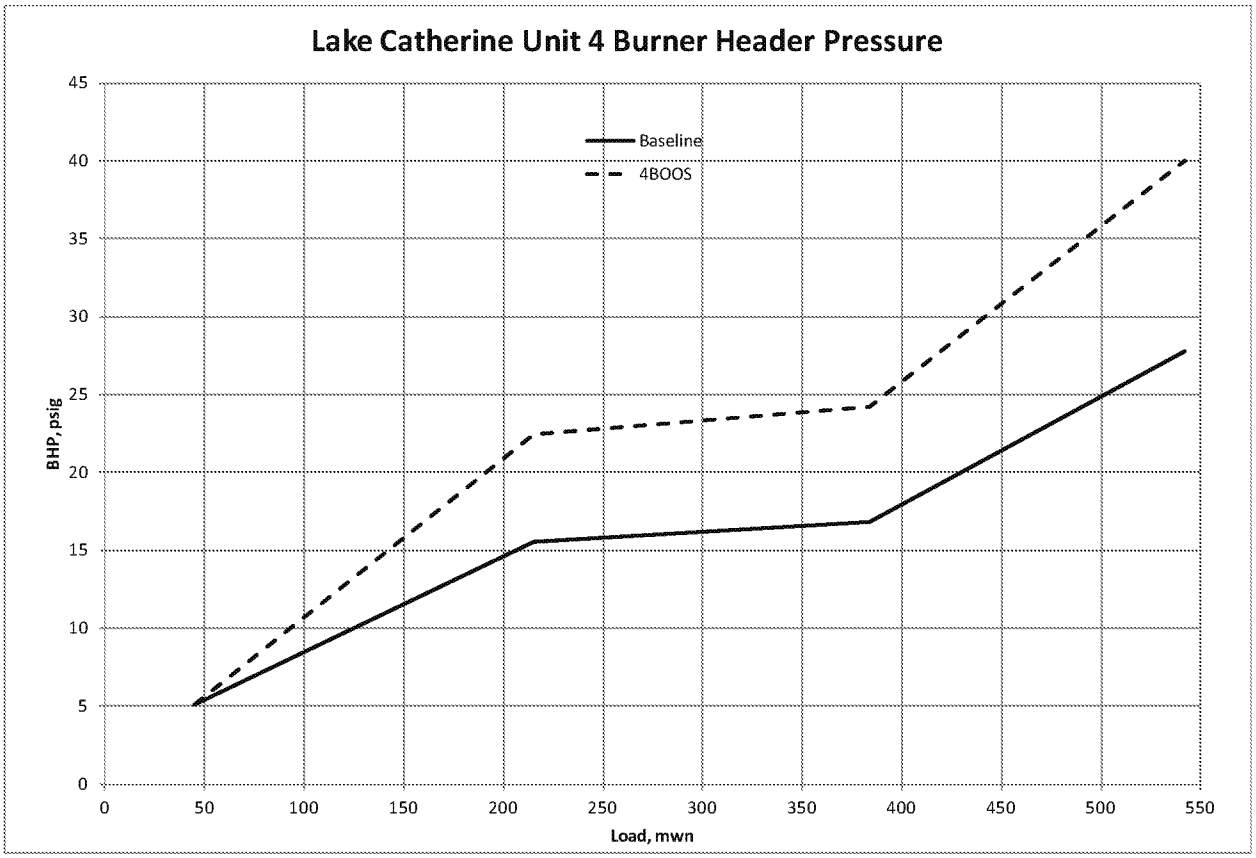
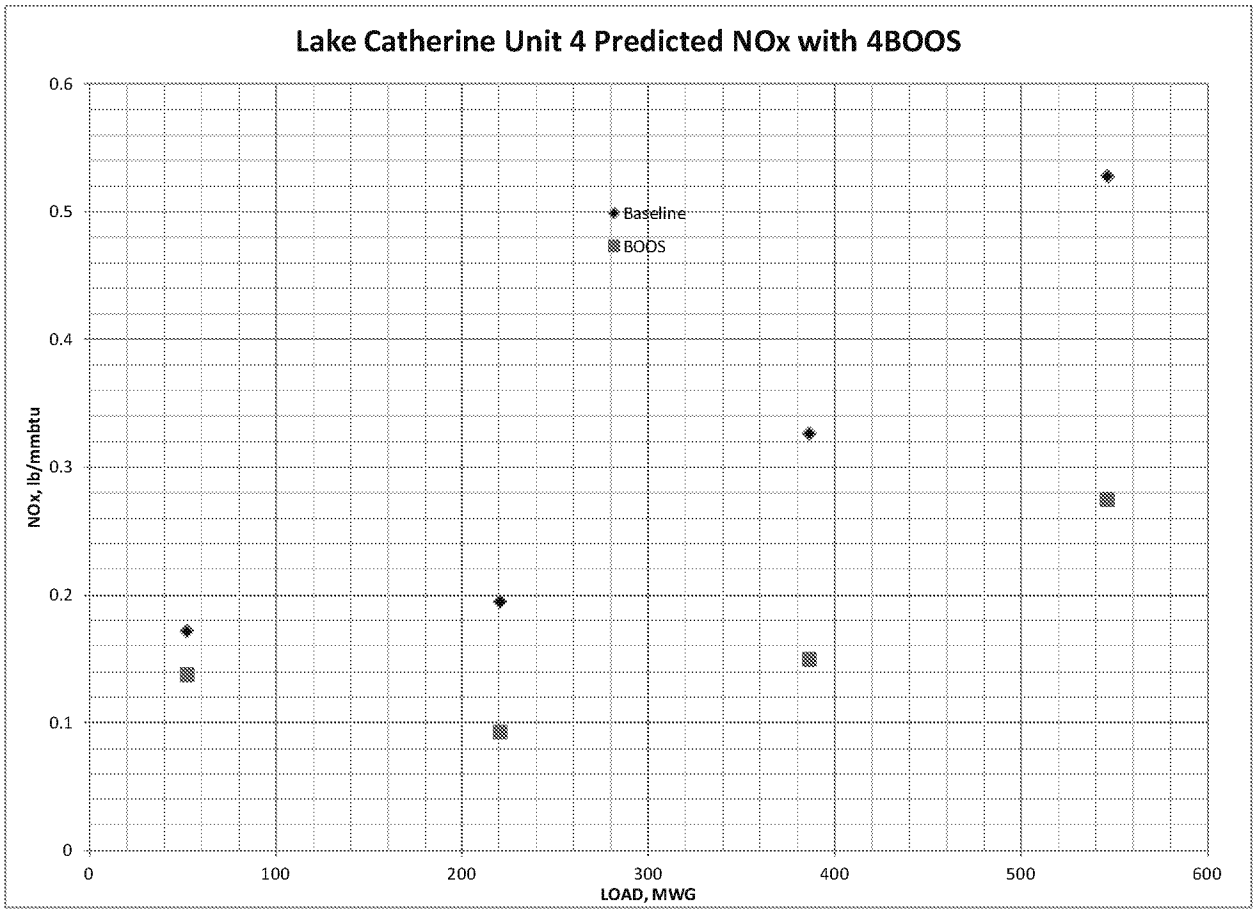


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



ADEQ
ARKANSAS
Department of Environmental Quality

April 5, 2017

Kelly McQueen, Assistant General Counsel
Entergy Arkansas, Inc.
425 W Capitol Avenue
P.O. Box 551
Little Rock, Arkansas 72201

Dear Kelly McQueen:

The Arkansas Department of Environmental Quality (ADEQ) is in the process of developing a state implementation plan (SIP) revision to address disapproved provisions in the 2008 Arkansas Regional Haze SIP (2008 AR RH SIP) and replace the federal implementation plan (FIP) promulgated by EPA on September 27, 2016. As part of this process, ADEQ requests that Entergy Arkansas, Inc. (EAI) provide supplemental information to inform ADEQ's best available retrofit technology (BART) determination for sulfur dioxide (SO_2) at White Bluff units 1 and 2.

In the "State of Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan" (AR RH FIP), EPA determined that BART for White Bluff was dry flue gas desulfurization (Dry FGD) technology based on the thirty year expected useful life of the Dry FGD equipment; however, EPA did not appropriately take into account the remaining useful life of the White Bluff units themselves. White Bluff unit 1 began operating in 1980 and unit 2 began operating in 1981. Given the age of the units and expected market trends for coal compared to other fuels and technologies used to generate electricity, it is not reasonable to assume that White Bluff will still be powered by coal in 2051 (thirty years after the compliance date in the AR RH FIP and 70 years after beginning operation) and to base cost-effectiveness calculations on such an assumption.

EAI has provided several analyses in support of comments on EPA's AR RH FIP with various assumptions about dates by which Entergy could commit to cease coal-fired operations at White Bluff units and what interim controls would be necessary to satisfy BART requirements under 40 CFR 51 Appendix Y. ADEQ requests that EAI confirm whether such analyses that are already on the record are still accurate. Specifically, please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400–11,800 per ton under the assumption of four to five years of remaining useful life is still accurate. Additionally, please confirm whether the cost-effectiveness values for Dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six to seven years of remaining useful life is still accurate. Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2

ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY
5301 NORTHSHORE DRIVE / NORTH LITTLE ROCK / ARKANSAS 72118-5317
TELEPHONE 501-682-0744 / FAX 501-682-0880 / www.adeq.state.ar.us

based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 to EPA on the AR RH FIP.

In addition to verifying cost-effectiveness values already on the record, ADEQ requests that EAI also provide additional supplemental information for consideration. Specifically, please provide an analysis of the expected cost-effectiveness values for Dry FGD with compliance based on the following scenarios: seven to eight years remaining useful life, fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and nineteen years remaining useful life (sixty years from the start of operations at White Bluff).

We request that EAI provide this supplemental information by 4:30 p.m. on April 21, 2017. Thank you for your prompt response to this request for supplemental information.

Sincerely,

Stuart Spencer
Associate Director, Office of Air Quality

ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY
5301 NORTHSHORE DRIVE / NORTH LITTLE ROCK / ARKANSAS 72118-5317
TELEPHONE 501-682-0744 / FAX 501-682-0880 / www.adeq.state.ar.us

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-17-039

April 21, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Response to Information Request
Entergy Arkansas, Inc. – White Bluff Plant
AFIN: 35-00110 Permit No.: 0263-AOP-R10

Dear Mr. Spencer:

On behalf of Entergy Arkansas, Inc. (EAI), Entergy Services, Inc. (ESI) has reviewed your letter of April 5, 2017, regarding costs associated with potential SO_2 emissions control options at the White Bluff Plant. As requested, ESI provides the following responses to the questions posed by ADEQ in this letter. For convenience, these responses have been numbered in the order they appear in the April 5 letter.

Please note that, for all costs associated with dry flue gas desulfurization (dry FGD) controls, two separate cost ranges are provided. The first is the full capital cost estimate prepared by Sargent and Lundy (S&L) for Entergy, based on S&L's extensive experience estimating costs for similar projects at similar electric generating facilities. While ESI believes the full S&L capital cost estimate to be the most accurate representation of costs that would be borne by EAI and its ratepayers, the U.S. EPA has previously disallowed consideration of several components of this cost estimate, including escalation, interest during construction (IDC), and owner's costs. Recognizing this, ESI is also providing a second, partial, cost range that eliminates escalation, IDC, and owner's costs, even though the removal of such costs severely underestimates the actual amount EAI would incur to install SO_2 emissions controls at White Bluff. All capital costs are from S&L estimate 33787B issued November 18, 2016.[1] O&M costs are the same for both scenarios and are from S&L report SL-012831 issued July 14, 2015. All costs are in 2015 dollars.

1. **Please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400 – 11,800 per ton under the assumption of four to five years of remaining useful life is still accurate.**

   For a four- to five-year remaining useful life (RUL), the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $9,100-$11,000 based on the full costs and $6,900 to $8,200 based on the partial costs.

2. **Please confirm whether the cost effectiveness values for dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six-to-seven years of remaining useful life is still accurate.**

   For a six- to seven-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $7,100-$8,000 based on the full costs and $5,400-$6,100 based on the partial costs.[2]

[1] S&L revised its prior cost estimates, as explained in EAI's Petition for Reconsideration of the final FIP. *See* EAI Petition for Reconsideration, at 8 n. 31 (Nov. 23, 2016). These revised cost estimates have been used to respond to the Department's questions.
[2] EAI Petition for Reconsideration, at 8.

3. **Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2 based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 on the AR RH FIP.**

   To meet an emission limit of 0.6 lb/MMBtu, EAI would purchase coal with a sulfur content lower than 0.6 lb/MMBtu to provide an adequate margin for compliance. Based on coal market information available to Entergy's fuel supply group, the cost premium for coal purchased to meet a SO_2 limit of 0.6 lb/MMBtu is expected to be approximately 50 cents per ton of coal purchased. Based on this cost premium, a typical low-sulfur coal heat content of 8,800 btu/lb (as supplied), and the annual heat input value utilized in the S&L dry FGD cost estimate (55,829,551 MMBtu/year), the annual cost premium associated with the use of low-sulfur coal at one White Bluff unit is estimated to be approximately $1,600,000.[3]

4. **Please provide an analysis of the expected cost-effectiveness values for dry FGD with compliance based on the following scenarios:**

   a. **Seven to eight years of remaining useful life,**

      For a seven- to eight-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $6,500-$7,200 based on the full costs and $5,000-$5,500 based on the partial costs.

   b. **Fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and;**

      For a 15-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,500 based on the full costs and $3,500 based on the partial costs.

   c. **Nineteen years of remaining useful life (sixty years from the start of operations at White Bluff).**

      For a 19-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,050 based on the full costs and $3,175 based on the partial costs. It should be noted that the White Bluff units first began commercial operation on August 21, 1980 (Unit 1) and July 23, 1981 (Unit 2). Assuming that compliance with a SIP limit for a dry FGD system would be required in 2022, a 19-year RUL would end in 2041.

We appreciate the Department's consideration of this information. Should you or your staff have any further questions or require any additional information, please feel free to contact me at (501) 377-5760, Tracy Johnson at (501) 377-4033, or David Triplett at (501) 377-4030.

Sincerely,

Kelly McQueen

Associate General Counsel

KMM/dct

[3] EAI cannot estimate the cost-effectiveness of meeting a SO_2 limit of 0.6 lb/MMBtu based on the use of low sulfur coal given that the actual sulfur content of low sulfur coal varies, making it difficult to estimate the tons of SO_2 that would be reduced, particularly in comparison to the historical emissions. Furthermore, to estimate a predicted annual average SO_2 emission rate based on operation with low sulfur coal could under-estimate the cost effectiveness of this option.

Entergy Services, Inc.
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel. 501-377-5760
Fax 501-377-5814
kmcque1@entergy.com

Kelly McQueen
Assistant General Counsel

August 18, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Updated BART Five-Factor Analysis for SO_2 at Entergy White Bluff Units 1 and 2

Dear Mr. Spencer:

Entergy Arkansas, Inc. (Entergy) respectfully submits the following Updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for sulfur dioxide (SO_2) for Units 1 and 2 at the White Bluff Steam Electric Station (Updated FFA). The submittal is an update to the original FFA submitted on February 21, 2013, with revisions on June 10 and October 15, 2013. Confidential Business Information has been redacted. A hard copy of the Updated FFA which includes the redacted information will be submitted to the Department concurrently, in accordance with Regulation No. 18.1402.

The Updated FFA updates the emissions baseline period used for modeling White Bluff's baseline visibility impairment and estimate the cost-effectiveness of the SO_2 controls evaluated, incorporates new information regarding the remaining useful life (RUL) of the units, assesses a new control scenario representing combustion of only low-sulfur coal (LSC), incorporates additional information related to control options involving Dry Sorbent Injection (DSI), updates the modeling to reflect the newest methodologies for speciating particulate matter emissions into its constituents, and amends the SO_2 BART conclusion in light of the new information. The Updated FFA concludes that combustion of LSC constitutes BART for White Bluff Units 1 and 2 in light of the updated RUL. The proposed BART emission rate for SO_2 for each unit is 0.6 pounds per MMBtu

(lb/MMBtu) on a rolling 30-day average. Entergy urges ADEQ to incorporate this analysis into its anticipated revisions to the SO_2 provisions in the Regional Haze State Implementation Plan (SIP) for the first planning period.

The Updated FFA addresses only SO_2 BART, and does not address BART for nitrogen oxides (NOx). Last month, ADEQ released a draft Regional Haze SIP Revision for the first planning period that concludes compliance with the updated Cross-State Air Pollution Rule constitutes BART for NOx. Entergy submitted comments in support of this conclusion on August 14, 2017. Nonetheless, Entergy would be amenable to accepting a specific emission limit for NOx at White Bluff Units 1 and 2, based on the installation of low NOx burners and separated overfire air (LNB/SOFA), but is still in the process of tuning the LNB/SOFA recently installed at White Bluff Unit 2.

We are happy to answer any questions you may have about the Updated FFA.

Sincerely,

Kelly M. McQueen
Assistant General Counsel –
Environmental (Lead)
Entergy Services, Inc.

Attachment:

Updated Five Factor Analysis

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Prepared by:

TRINITY CONSULTANTS
5801 E. 41st St., Suite 450
Tulsa, OK 74135
(918) 622-7111

August 18, 2017

Trinity Project 173702.0014

EHS solutions delivered uncommonly well

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY 1-1
- **1.1 Report Updates** 1-1
- **1.2 Summary of Updated BART Five Factor Analysis** 1-2

2 INTRODUCTION AND BACKGROUND 2-1

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT 3-1
- **3.1 Baseline Emission Rates** 3-1
- **3.2 Baseline Visibility Impairment** 3-2

4 SO_2 BART EVALUATION 4-1
- **4.1 Identification of Available Retrofit SO_2 Control Technologies for Unit 1 and Unit 2** 4-1
- **4.2 Eliminate Technically Infeasible SO_2 Control Technologies for Unit 1 and Unit 2** 4-1
  - *4.2.1 Fuel Switching – Low-Sulfur Coal* 4-1
  - *4.2.2 Dry Sorbent Injection* 4-1
  - *4.2.3 Dry / Semi-Dry Flue Gas Desulfurization* 4-2
  - *4.2.4 Wet Flue Gas Desulfurization* 4-3
- **4.3 Rank of Technically Feasible SO_2 Control Options by Effectiveness for Unit 1 and Unit 2** 4-3
- **4.4 Evaluation of Impacts for Feasible SO_2 Controls for Unit 1 and Unit 2** 4-3
  - *4.4.1 Remaining Useful Life* 4-4
  - *4.4.2 Cost of Compliance* 4-4
  - *4.4.3 Energy Impacts and Non-Air Quality Impacts* 4-6
- **4.5 Evaluation of Visibility Impact of Feasible SO_2 Controls for Unit 1 and Unit 2** 4-6
- **4.6 BART for SO_2 for Unit 1 and Unit 2** 4-8

APPENDIX A. CONTROL COST INFORMATION A-1

APPENDIX B. BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT B-1

APPENDIX C. REFINED PM SPECIATION CALCULATIONS C-1

LIST OF TABLES

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents) 3-2

Table 3-2. Baseline Visibility Impairment 3-2

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2 4-1

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies 4-3

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs 4-5

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes 4-5

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2 4-7

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003) 4-7

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003) 4-8

Table B-1. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant B-1

Table B-2. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant B-2

1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.

[redacted]

3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).

4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).

5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.

6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

---

[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *...an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by...[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

---

[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., "screening") modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff's units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

---

[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4 SO_2 BART EVALUATION

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

[16] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

4.4.1 Remaining Useful Life

[redacted]

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

[redacted]

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

---

[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is [redacted]. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, [redacted][20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	8,900
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	8,807
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	8,209
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	8,153
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	7,771
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	7,764
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	7,683
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	7,137
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	7,088
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	5,883
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost [redacted] and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), [redacted]

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

---

[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

APPENDIX B. BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

Entergy

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-012831
Final, Rev. 1
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

EPA-HQ-2018-002296

CONTENTS

Section **Page**

EXECUTIVE SUMMARY **1**

1. PURPOSE **1**

2. APPROACH **1**

2.1 TECHNOLOGY SELECTION 1

2.2 CONTRACTING APPROACH 1

2.3 CAPITAL COST DEVELOPMENT 2

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS **5**

3.1 DRY FGD ISLAND 5

3.2 REAGENT HANDLING SYSTEM 7

3.3 BYPRODUCT HANDLING SYSTEM 7

3.4 FLUE GAS HANDLING SYSTEM 8

3.5 ELECTRICAL BOP SYSTEM 8

3.6 I&C BOP SYSTEM 8

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS **10**

4.1 EPC CONTRACT PRICE 10

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE 19

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS 24

4.4 FIXED OPERATING AND MAINTENANCE COSTS 25

4.5 SULFUR DESIGN BASIS SENSITIVITY 25

5. SUMMARY **27**

6. ATTACHMENTS **28**

ED_002110_00032341-00025

EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $991,489,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $8,132,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the

construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. The costs provided in this report are in 2015 dollars.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones based on a project start date of January 2015.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication

Month	Date	Milestone
17	June 2018	Physical Flow Model Completed
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were

included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the

new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design, based on the current coal contract sulfur limit.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs, based on the annual heat input weighted average emission from 2009 through 2013.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Compliance deadline of December 2020, based on a project start date of January 2015.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps

- Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
   - Three absorber vessels per unit, with access doors
   - Rotary atomizers, two spare atomizers included
   - Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
   - Heating and ventilation
   - Vacuum piping
   - SDA Superstructure
   - Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
   - New baghouse, including pulse jet cleaning system and all appurtenances
   - Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
   - One recycle silo with bin vent filter per unit, 8-hour total capacity
   - Two recycle mix tanks per unit
   - Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
   - Agitators for each tank
   - Baghouse ash handling system common to both units
   - Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
   - Pneumatic pressure blowers (8 x 33⅓ %)
   - Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
   - Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
   - Includes motors - no spare motor included
   - Cost estimate based on budgetary proposal from Alstom
   - Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

f. Interconnecting Ductwork, per unit
   - ID fan outlet to absorber inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Absorber outlet to baghouse inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm

2. FGD Island Foundations and Enclosures
   a. Absorber tower foundations including caissons
   b. Baghouse area foundations including 18" auger cast piles 60' long
   c. Booster fan area foundations
   d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)
   e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)
   f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas
   g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)
   h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)
   i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. Reagent Storage and Handling, common to both units:
   a. Lime rail car unloader:
      - Lime delivery via 25-car unit train
      - System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
      - Enclosed railcar unloading building
      - One vacuum pneumatic system operating to unload a car
      - Pneumatic vacuum exhausters (2 x 100%)
      - Filter separator with vacuum-to-pressure transfer hopper and valves
      - One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack

- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:
   - Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
   - 32' diameter and 95' height to top
   - 1,200-tons storage, each
   - Continuous level detection systems
   - Bin vent filters
   - Live bottom hopper outlets
   - Rotary airlock assemblies
   - Lime transfer systems:
     - Pressure pneumatic conveying system from lime storage silos to lime day bins
     - Pneumatic pressure blowers (3 x 100%)
     - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. <u>Byproduct Handling System, common to both units</u>

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

1. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling BOP, per unit
   a. ID fan outlet to absorber inlet ductwork insulation; 6" with lagging6" insulation with lagging
   b. Absorber outlet to baghouse inlet ductwork insulation; 6" with lagging
   c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork insulation; 6" with lagging
   d. Concrete foundations for all flue gas ductwork
   e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP
   a. Roadwork
   b. Site grading
   c. Soil removal earthwork
   d. Excavation, backfill, and compaction for all foundations
   e. Storm sewer work
   f. Two-cell pond for wastewater storage of process water/slurry
   g. Laydown Area
      - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.
   h. Highway Intersection Upgrade to provide sufficient plant access for construction period
      - New Bypass Lane on Westside of Highway 365
      - New Southbound Left Turn Lane on Highway 365
      - New Northbound Merge Lane on Highway 365
      - New Northbound Right Turn Lane on Highway 365
      - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
      - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
      - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing
   i. New warehouse building 200' x 75' x 15', including substructure and superstructure.

7. Mechanical BOP System
   a. Interconnecting piping, above-ground and buried
   b. Valves for interconnecting piping, above-ground and buried
   c. Lime slaking water storage tank, 115,000-gallon capacity

d. Slaker water 3" in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
   - Between lime railcar unloading enclosure and lime silos
   - Between lime silos and lime day bins
   - From baghouse hoppers to recycle silos and FGD by-product silo
   - From lime slurry storage tanks to absorber
   - From recycle slurry storage tank to absorber
   - Concrete foundations including caissons for all pipe racks
   - Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
   - Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150' TDH
   - Four reagent prep/recycle sump pumps, 120 gpm @ 150' TDH
   - Two lime silo and unloading area sump pumps, 120 gpm @ 150' TDH
   - Two by-product ash silo area sump pumps, 120 gpm @ 150' TDH
   - Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200' TDH
   - Two lime slaking water pumps, 750 gpm @ 100' TDH
   - One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100' TDH, including new intake structure, piping and valves
   - Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
   - Air compressors; 2 x 100%, 250 scfm each @ 100 psig
   - IA dryers w/filters; 2 x 100%, 250 net scfm each
   - Air receivers; 2 x 100%
   - Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
   - Heat-traced piping

i. Service Air System, common to both units
   - Air compressors; 2 x 100%
   - Air receivers; 2 x 100%

j. Field painting
   - Multiple coat system used for exposed ductwork only
   - Inorganic zinc primer and polyurethane system used for steel

- Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation
   a. Hazardous material accumulation building
   b. Ash handling maintenance building
   c. Drainage ditch
   d. Pipe trench
   e. Fabrication shop
   f. Existing contractor electrical hook up
   g. Existing drainage ditches, rerouted with new concrete trenches
   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
   i. Rail Yard Extension, common to both units
      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
   j. Fire Protection System Modifications
      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System
   a. One 115-kV, 1200A isolation disconnect switch
   b. One startup transformer
   c. Two unit auxiliary transformers (UAT)
   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
   f. Two 480-V double ended switchgear buses per unit (total of four)
   g. Six 480-V motor control centers per unit (total of twelve)
   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
   i. Two isolated phase UAT tap bus extensions

j. Non-segregated phase bus

k. Medium-voltage cable

l. Low voltage, control and instrumentation cable, as necessary

m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

a. Controls System based on an estimated number of I/O points:

- Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
- Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

b. CEMS, per unit

- Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

- Project Development (through EPC Award) – 25 months, equivalent of 10 people

- Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

   The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

   a. Commissioning Support Specialists – 8 months, 2 people

   The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

   The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

   The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

   a. Conceptual Study Support
   b. EPC Specification Supporting Documents
   c. Project Schedule Development
   d. EPC Specification Development
   e. EPC Bid Evaluation and Contract Conformance
   f. General Project Support
      - Monthly Project Status Meetings
      - Weekly Teleconferences
      - Overall Coordination
      - Project Administration
      - Site Visits and Travel
   g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
   h. Design Review of Drawing Submittals
   i. Technical support during design, fabrication, construction, commissioning, and testing
   j. Equipment vendor QA/QC audits

   The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

   The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol

b. Procuring the services of the testing contractor

c. Overseeing the performance test campaign

d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment

EPA-HQ-2018-002296

schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

ED_002110_00032341-00049

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost[1]	$/MWh	$43.35

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Value
Dry FGD System Parameters		
Reagent Consumption	lb/hr	5,900
Byproduct Waste Production	lb/hr	13,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	65
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,422,000
Byproduct Waste Disposal Cost	$/year	$308,000
Aux Power Cost	$/year	$3,012,000
Water Cost	$/year	$205,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,319,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.57 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.57 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses,

and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.57 lb/MMBtu	Cost Reduction for 1.2 to 0.57 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,000 tons each	- $4,717,000
Two lime day bins	650 tons each	300 tons each	- $321,000
Two detention lime slakers	13 tons/hour each	6 tons/hour each	- $134,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $472,000

Two FGD by-product storage silos	3,000 tons each	1,200 tons each	- $3,391,000
One lime slaking water storage tank	175,000 gallons	100,000 gallons	-$34,000
		TOTAL Differential	**- $9,069,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.57 lb SO_2/MMBtu is approximately $9M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A

2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A

3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule

4. Monthly Progress Payment Schedule for White Bluff DFGD Project

5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates

6. S&L Estimating Documentation: Escalation Projections

7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing

8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	12/18/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387B
Cost index	ARPBL

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	83,083,008		1,085,764
Material	50,642,339		
Subcontract	313,285,100		
Process Equipment	23,037,000		
	470,047,447	470,047,447	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,816,000		
91-2 Cost Due To OT 5-10's	11,616,000		
91-4 Per Diem	10,858,000		
91-5 Consumables	831,553		
91-6 Freight on Material	2,532,000		
91-8 Sales Tax	7,821,000		
91-9 Contractors G&A	16,696,000		
91-10 Contractors Profit	8,348,000		
	64,518,553	534,566,000	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	55,847,000		
	79,747,000	614,313,000	
Escalation:			
96-1 Escalation on Material	6,012,000		
96-2 Escalation on Labor	18,769,000		
96-3 Escalation on Subcontract	37,429,000		
96-4 Escalation on Process Eq	2,115,000		
96-5 Escalation on Indirects	11,600,000		
	75,925,000	690,238,000	
Total EPC Cost		***690,238,000***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	748,784,000	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	761,328,000	
Project Contingency :			
110 Project Contingency	102,810,000		
	102,810,000	864,138,000	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	866,411,000	
Interest During Construction:			
130 Interest During Constr.	125,078,000		
	125,078,000	991,489,000	
Total		***991,489,000***	

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,914	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,152,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM			3,267,828	113,961	7,898,036	11,165,864
121	CIVIL BOP	570,000		8,073,474	196,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,959,000	6,882,913	115,659	9,189,021	19,028,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,655,684	290,576	20,231,688	43,186,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,984	841,993	3,424,993
	TOTAL DIRECT	**313,285,100**	**23,037,000**	**50,642,339**	**1,085,764**	**83,083,008**	**470,047,447**

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU. Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			**FGD ISLAND**									
	23.00.00		STEEL									
		23.13.75	SILO									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				(273,000)		-690		(50,428)	(323,428)
			STEEL				(273,000)		-690		(50,428)	(323,428)
	31.00.00		MECHANICAL EQUIPMENT									
		31.45.00	FGD EQUIPMENT									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
			MECHANICAL EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			10 FGD ISLAND			**297,904,000**	**(1,649,000)**		**-7,814**		**(680,533)**	**295,574,467**
101			**FGD ISLAND FOUNDATIONS AND ENCLOSURES**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					961,632	13,324		1,445,136	2,406,768
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					1,043,634	14,211		1,541,379	2,585,013

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					2,005,266	27,536		2,986,515	4,991,781
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					1,204,900	11,798		779,520	1,984,420
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					5,402,720	38,437		3,560,015	8,962,735
			STEEL					8,607,620	50,235		4,339,534	10,947,154
	24.00.00		ARCHITECTURAL									
		24.17.00	ELEVATOR									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
31.00.00			MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
34.00.00			HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
36.00.00			INSULATION									
		36.13.00	DUCT									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergere & Lunsford

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			**6,000,000**	**2,046,000**	**3,162,954**	**59,192**		**4,646,650**	**15,855,604**
105			**BYPRODUCT HANDLING SYSTEM**									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**1,089,675**	**107,800**		**7,935,771**	**23,610,546**
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
			DAMPERS & ACCESSORIES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691
			111 FLUE GAS SYSTEM					**3,267,828**	**113,961**		**7,898,036**	**11,165,864**
121			**CIVIL BOP**									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						28,506		5,197,453	5,197,453
		21.17.00	EXCAVATION									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						4,868		439,945	439,945
		21.19.00	DISPOSAL									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						483		38,288	38,288
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						172		13,674	13,674
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					110,000	2,299		165,839	275,839
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					1,065,011	3,448		335,555	1,400,566
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					3,346,203	19,569		1,533,638	4,879,841
		21.71.00	TRACKWORK									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			220,000						220,000
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			225,000		5,301,214	68,546		8,453,678	13,974,892
22.00.00			CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
24.00.00			ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
26.00.00			MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
27.00.00			PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209
31.00.00			MECHANICAL EQUIPMENT									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					93,638	1,311		89,786	183,423
			MECHANICAL EQUIPMENT					93,638	1,311		89,786	183,423
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					187,275	196		12,544	199,819
			HVAC					187,275	196		12,544	199,819
	36.00.00		INSULATION									
		36.99.00	INSULATION, MISCELLANEOUS									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					20,430	196		10,000	30,430
			INSULATION					20,430	196		10,000	30,430
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					187,275	196		12,452	199,727
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					100,000	230		18,862	118,862
			ELECTRICAL EQUIPMENT					287,275	426		31,314	318,589
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			350,000						350,000
			PROJECT INDIRECT			350,000						350,000
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						517		41,022	41,022
			DEMOLITION						517		41,022	41,022
	21.00.00		CIVIL WORK									
		21.17.00	EXCAVATION									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,340.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					156,460	8,154		646,677	803,138
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					690,804	9,407		1,020,272	1,711,076
			CIVIL WORK					847,264	17,561		1,666,949	2,514,214
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					94,530	3,307		197,455	291,985
			CONCRETE					94,530	3,307		197,455	291,985
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					653,110	4,709		436,166	1,089,276
			STEEL					653,110	4,709		436,166	1,089,276
	27.00.00		PAINTING & COATING									
		27.13.00	COATING									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			270,000						270,000
			PAINTING & COATING			270,000						270,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				709,200		405		27,707	736,907
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		151,519	279,019
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				220,000		368		23,404	243,404
		31.75.00	PUMP									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	PUMP									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				1,039,800		3,998		273,763	1,313,563
		31.83.00	TANK									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			728,000						728,000
			MECHANICAL EQUIPMENT			728,000	1,039,800	127,500	5,729		476,392	3,300,692
	35.00.00		PIPING									
		35.13.01	SS 304, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					198,156	7,494		579,755	777,911
		35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					609,874	36,441		2,819,087	3,428,961
		35.13.36	DUCTILE IRON, ABOVE GROUND, PROCESS AREA									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					162,000	3,594		259,256	421,256
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					127,845	4,471		345,897	473,742
		35.15.10	CARBON STEEL, BURIED									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	CARBON STEEL, BURIED									
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					912,807	19,533		1,511,045	2,423,852
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					50,024	1,554		120,219	170,243
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					33,640	2,413		186,633	220,273
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					81,550	1,071		82,873	164,423
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					2,860,785	4,228		327,099	3,187,884
			PIPING					5,036,681	89,799		6,231,866	11,268,547
36.00.00			INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,860		127,914	175,408
			INSULATION					47,494	1,860		127,914	175,408
41.00.00			ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					76,334	177		11,256	87,590
			ELECTRICAL EQUIPMENT					76,334	177		11,256	87,590
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
190			**DEMOLITION / RELOCATION**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						2,732		222,400	222,400
		11.22.00	CONCRETE									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						1,049		112,307	112,307
		11.23.00	STEEL									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						359		38,408	38,408
		11.24.00	ARCHITECTURAL									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						1,801		192,854	192,854
		11.31.00	MECHANICAL EQUIPMENT									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						290		26,852	26,852
		11.35.00	PIPING									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						162		17,401	17,401
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						2,299		212,920	212,920
			DEMOLITION						8,681		823,142	823,142
	21.00.00		CIVIL WORK									
		21.16.00	GENERAL EARTHWORK									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK					100,800	856		156,133	256,933
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,982		353,060	788,260
22.00.00			CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
23.00.00			STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,875		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					37,500	523		35,814	73,314
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					80,000	575		39,356	119,356
			MECHANICAL EQUIPMENT					117,500	1,755		132,736	250,236
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					46,200	48		3,094	49,294
			HVAC					46,200	48		3,094	49,294
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					1,806	45		3,518	5,323
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					12,660	400		30,944	43,604
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					6,913	191		14,761	21,674
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					160	66		5,122	5,282
			PIPING					21,539	702		54,344	75,883
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					126,500	132		8,411	134,911
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					14,700	55		3,511	18,211
			ELECTRICAL EQUIPMENT					141,200	187		11,921	153,121
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					258	4		266	524
		42.15.37	CONDUIT, RGS									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lunsford

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	DUCT BANK									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					585,000	107,471		6,646,649	7,236,649
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					645,120	18,538		1,521,037	2,166,157
		43.20.00	600V CABLE & TERMINATION									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					1,881,340	30,069		2,467,159	4,348,499
		43.40.00	5/8KV CABLE & TERMINATION									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					5,713,230	33,903		2,781,778	8,495,008
		43.50.00	15KV CABLE & TERMINATION									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					206,721	5,895		483,718	690,439
			CABLE					8,446,411	88,486		7,253,692	15,700,103
	51.00.00		SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
		51.15.27	CIRCUIT BREAKER									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	DISCONNECT SWITCH									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					15,000	69		3,847	18,847
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					15,000	69		3,847	18,847
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.13.00	CONTROL SYSTEM									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				1,500,000		2,299		148,690	1,648,690
		44.21.00	INSTRUMENT									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					578,000	7,946		651,967	1,229,967
		44.25.00	MONITORING EQUIPMENT									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Estimate No.: 33387B
Project No.: 13027-002
Estimate Date: 12/18/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

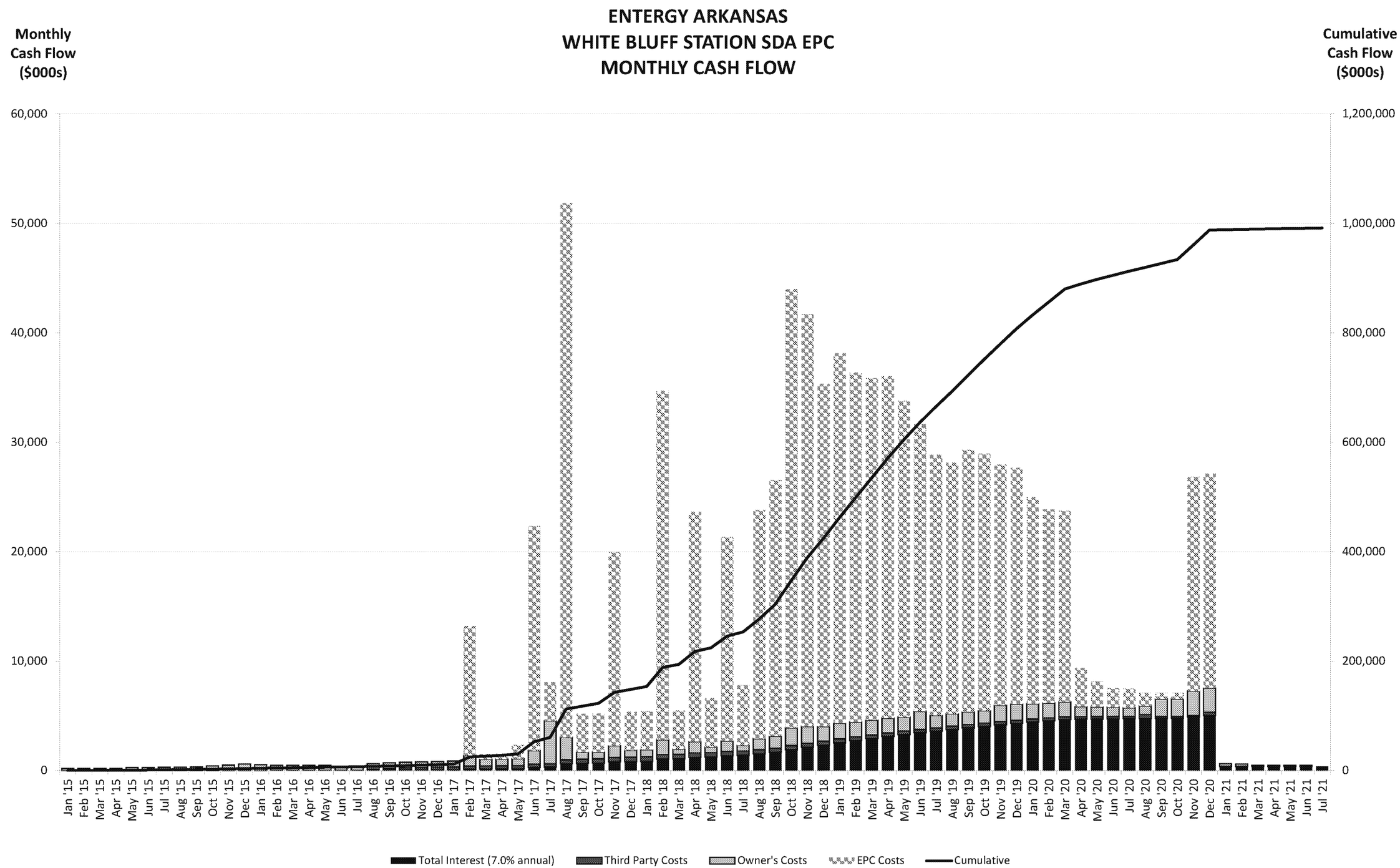
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

EPA-HQ-2018-002296

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow

ED_002110_00032341-00080


ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
MONTHLY CASH FLOW
Monthly Cash Flow ($000s)
Cumulative Cash Flow ($000s)
60,000
50,000
40,000
30,000
20,000
10,000
0
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Jan '15
Feb '15
Mar '15
Apr '15
May '15
Jun '15
Jul '15
Aug '15
Sep '15
Oct '15
Nov '15
Dec '15
Jan '16
Feb '16
Mar '16
Apr '16
May '16
Jun '16
Jul '16
Aug '16
Sep '16
Oct '16
Nov '16
Dec '16
Jan '17
Feb '17
Mar '17
Apr '17
May '17
Jun '17
Jul '17
Aug '17
Sep '17
Oct '17
Nov '17
Dec '17
Jan '18
Feb '18
Mar '18
Apr '18
May '18
Jun '18
Jul '18
Aug '18
Sep '18
Oct '18
Nov '18
Dec '18
Jan '19
Feb '19
Mar '19
Apr '19
May '19
Jun '19
Jul '19
Aug '19
Sep '19
Oct '19
Nov '19
Dec '19
Jan '20
Feb '20
Mar '20
Apr '20
May '20
Jun '20
Jul '20
Aug '20
Sep '20
Oct '20
Nov '20
Dec '20
Jan '21
Feb '21
Mar '21
Apr '21
May '21
Jun '21
Jul '21
Total Interest (7.0% annual)
Third Party Costs
Owner's Costs
EPC Costs
Cumulative

EPA-HQ-2018-002296

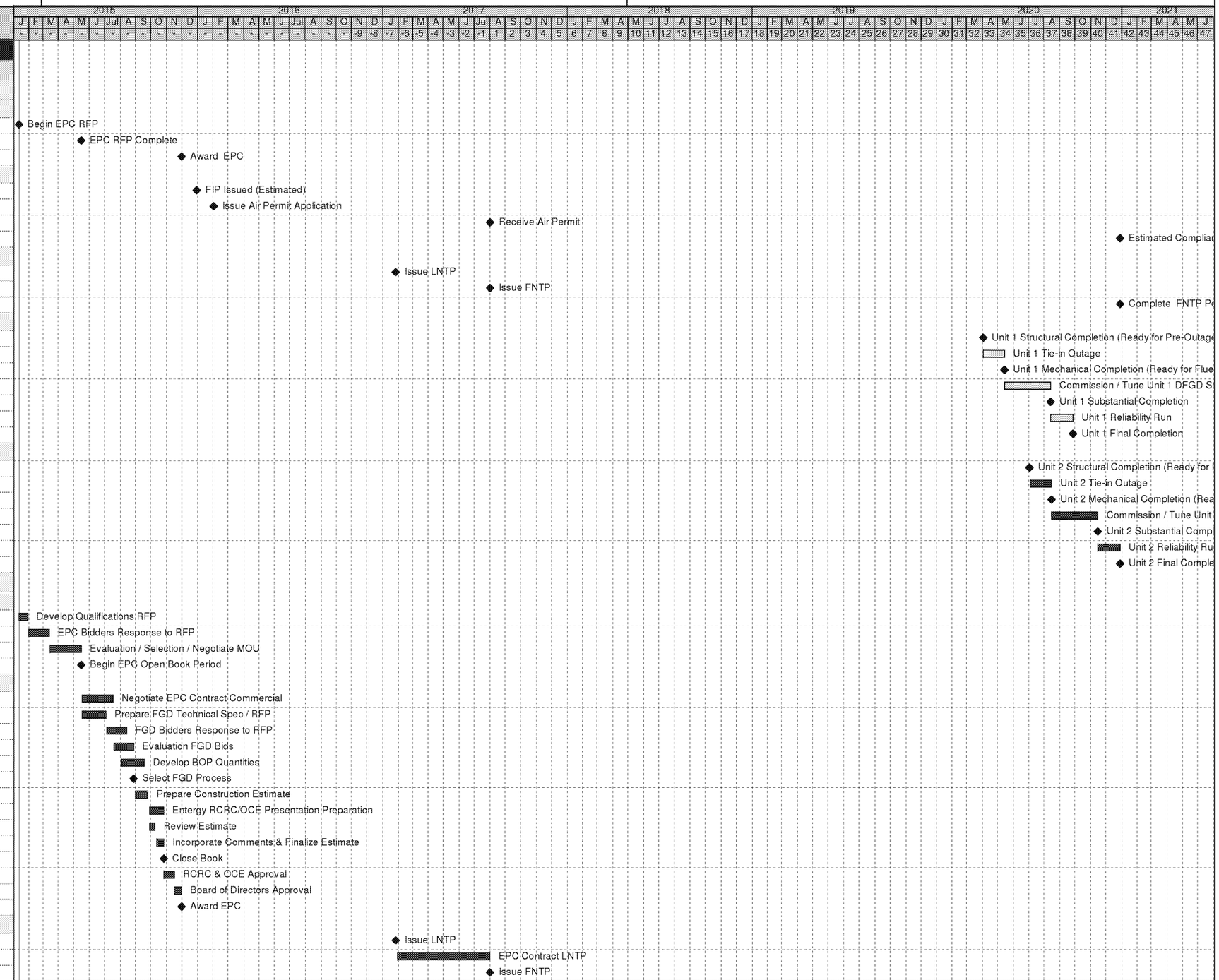
ATTACHMENT 3

Level 1 Preliminary Execution Schedule

ED_002110_00032341-00082

WHITE BLUFF FGD SCHEDULE (December 2020) 29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17



Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

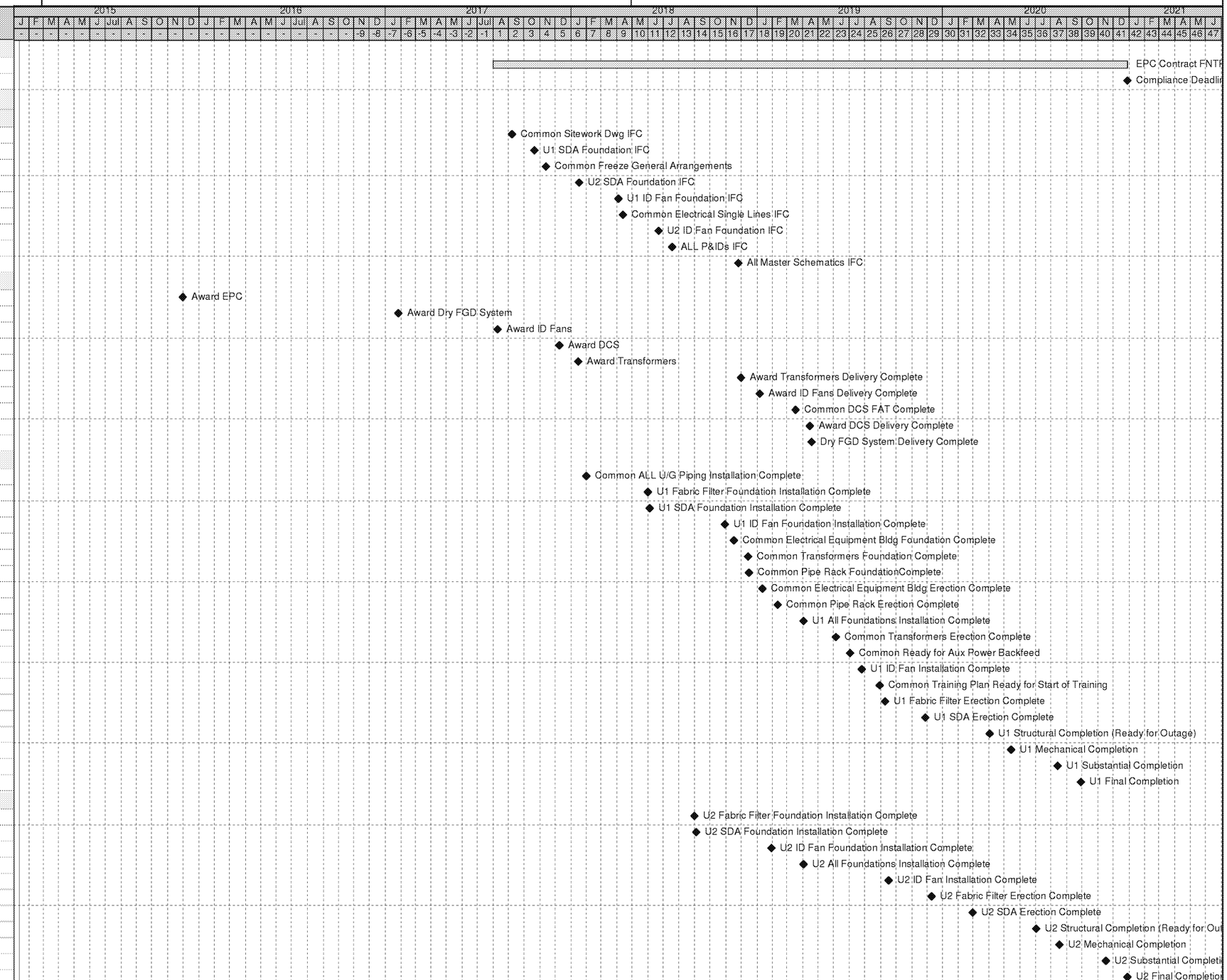
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20



Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

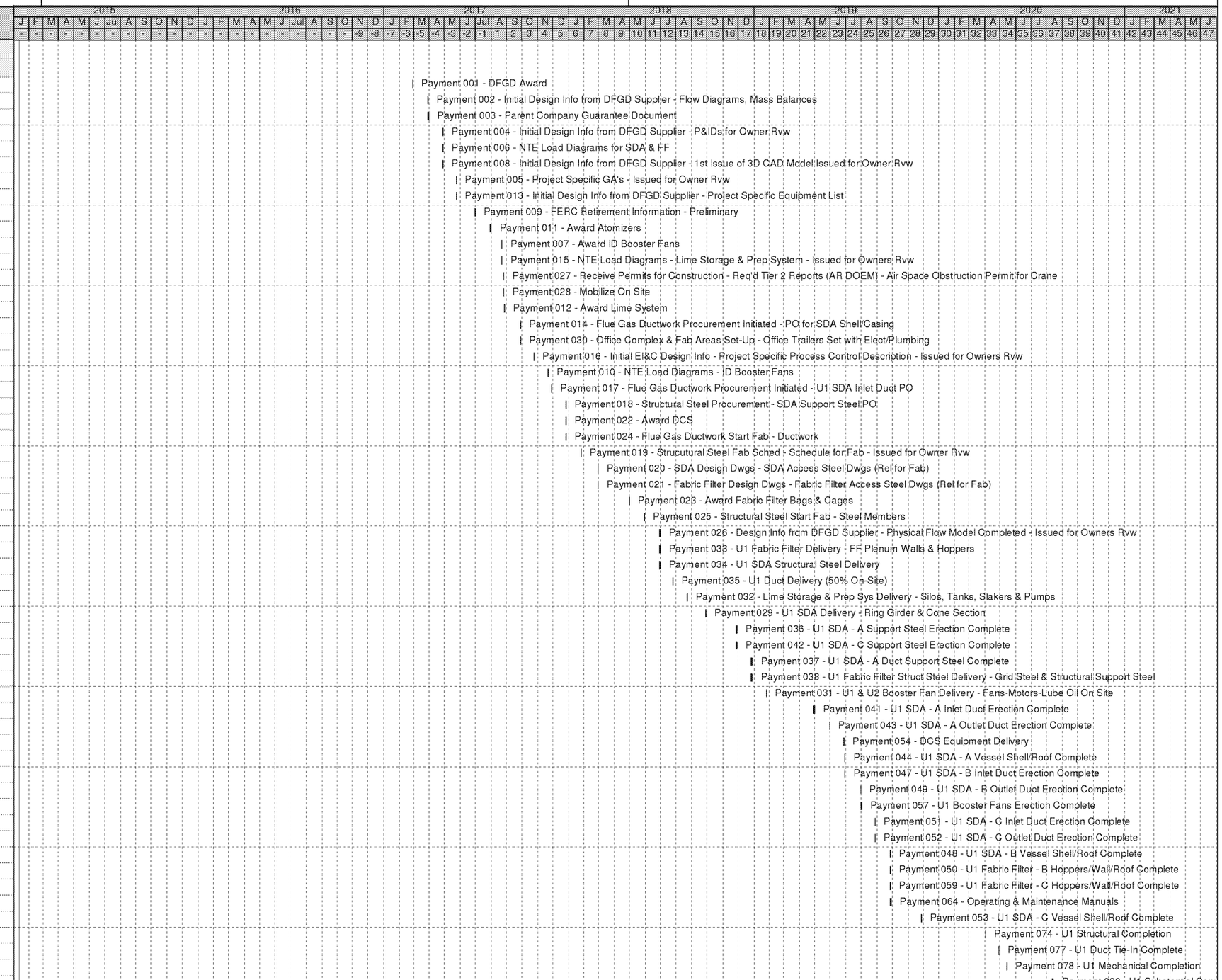
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

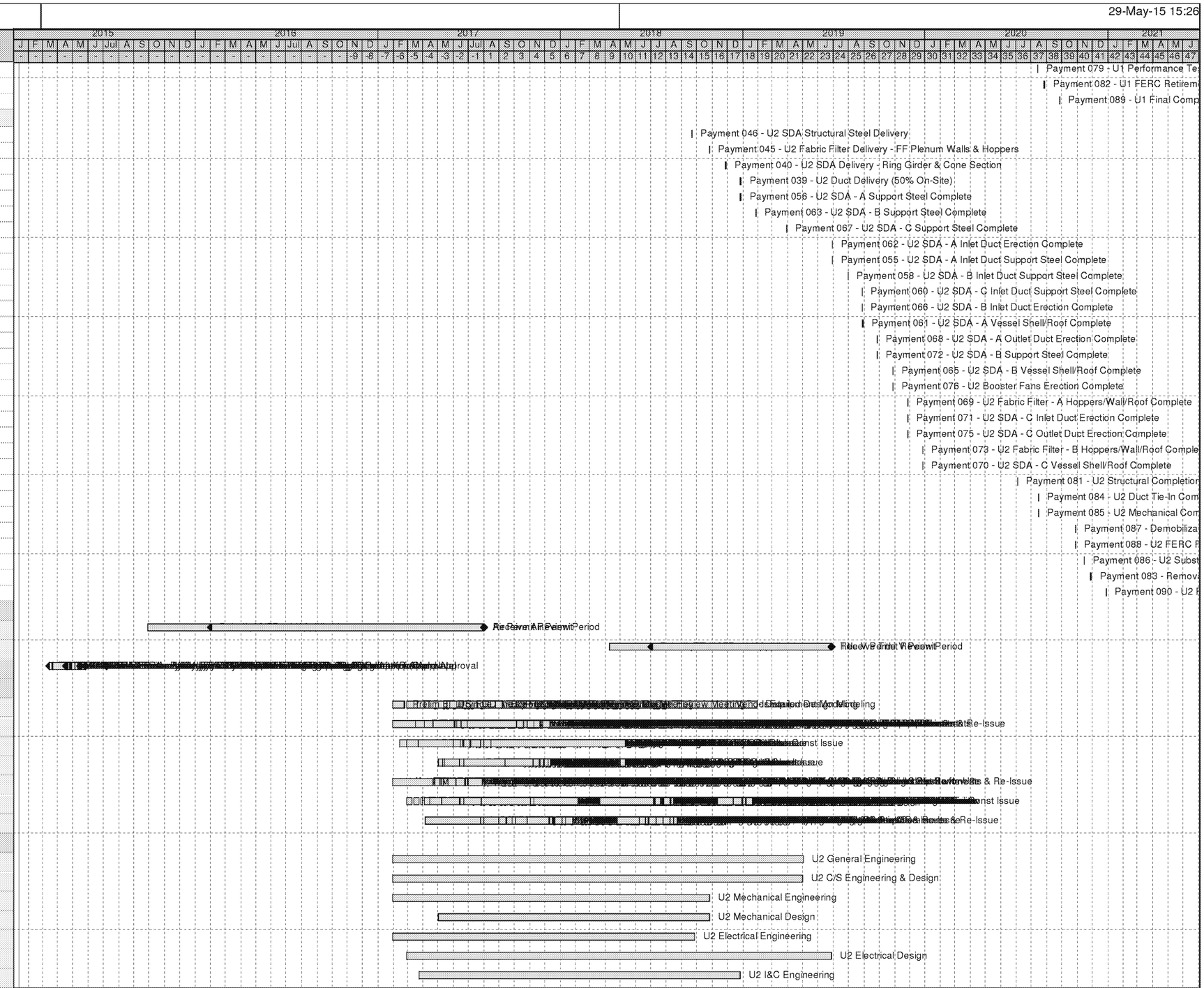
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

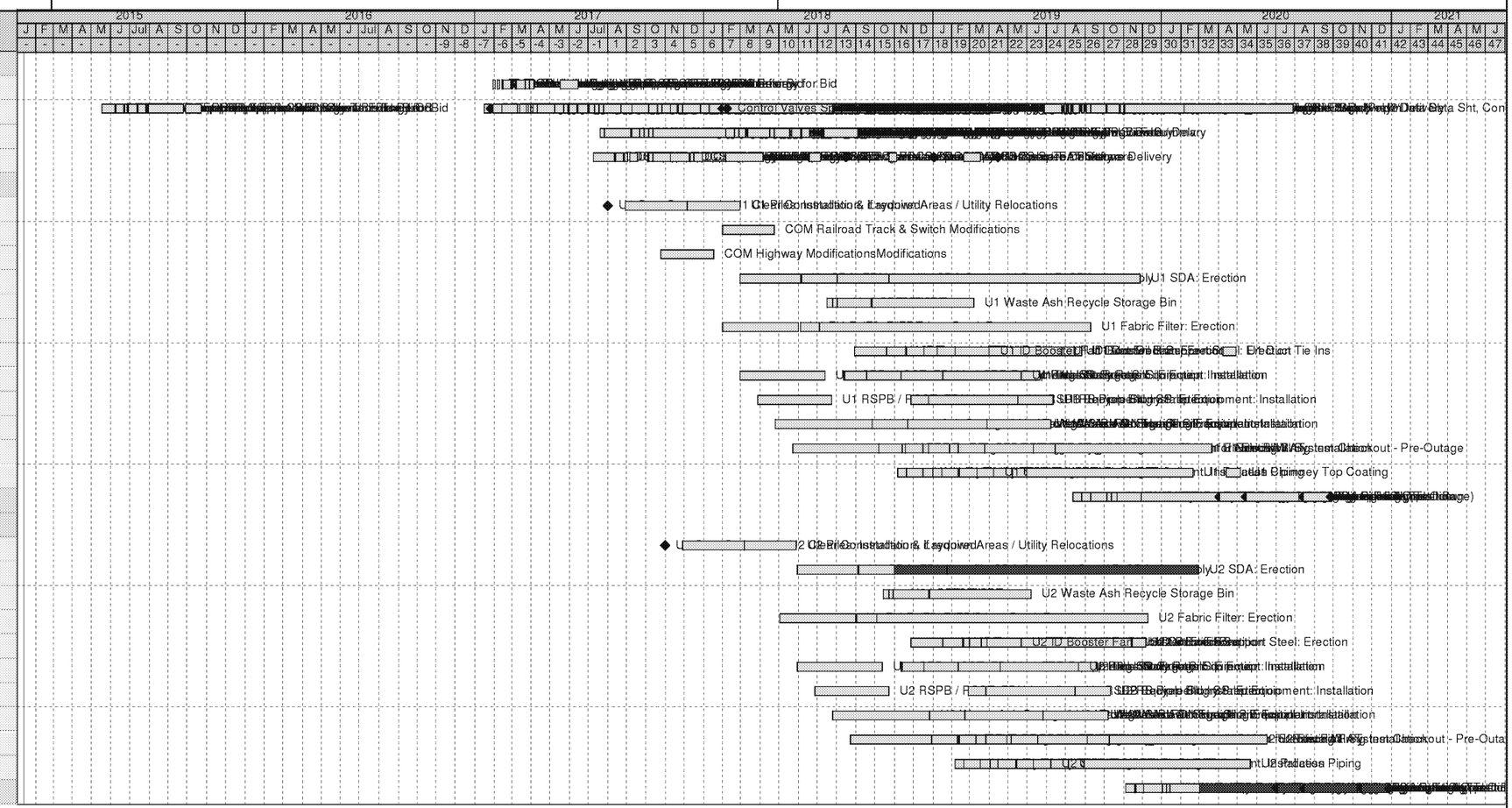
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
	Procurement	1357	18-May-15	28-Jul-20
	C/S/A Procurement	98	30-Jan-17	15-Jun-17
	Mechanical Procurement	1357	18-May-15	28-Jul-20
	Electrical Procurement	347	20-Jul-17	30-Nov-18
	I&C Procurement	448	10-Jul-17	15-Apr-19
	U1 Construction	720	02-Aug-17	05-May-20
	U1 Sitework	150	02-Aug-17	27-Feb-18
	U1 Railroad Track & Switch Mods	60	31-Jan-18	24-Apr-18
	U1 Highway Mods	60	25-Oct-17	16-Jan-18
	U1 SDA	457	28-Feb-18	28-Nov-19
	U1 Field Fabricated Tanks	170	16-Jul-18	08-Mar-19
	U1 Fabric Filter	419	31-Jan-18	09-Sep-19
	U1 ID Booster Fans / Ductwork	436	29-Aug-18	29-Apr-20
	U1 Lime Slurry	343	28-Feb-18	21-Jun-19
	U1 Recycle Slurry	337	29-Mar-18	12-Jul-19
	U1 Byproduct Handling	314	25-Apr-18	08-Jul-19
	U1 Auxiliary Power	478	23-May-18	20-Mar-20
	U1 Balance of Plant	390	07-Nov-18	05-May-20
	U1 System Testing and Commissioning	294	13-Aug-19	27-Sep-20
	U2 Construction	686	01-Nov-17	17-Jun-20
	U2 Sitework	150	01-Nov-17	29-May-18
	U2 SDA	458	30-May-18	28-Feb-20
	U2 Field Fabricated Tanks	170	15-Oct-18	07-Jun-19
	U2 Fabric Filter	419	02-May-18	09-Dec-19
	U2 ID Booster Fans / Ductwork	268	28-Nov-18	07-Dec-19
	U2 Lime Slurry	343	30-May-18	20-Sep-19
	U2 Recycle Slurry	337	28-Jun-18	11-Oct-19
	U2 Byproduct Handling	314	25-Jul-18	07-Oct-19
	U2 Auxiliary Power	476	22-Aug-18	17-Jun-20
	U2 Balance of Plant	337	06-Feb-19	21-May-20
	U2 System Testing and Commissioning	301	05-Nov-19	29-Dec-20



Remaining Work
Actual Work
WBS Summary
Critical Remaining Work
Milestone

TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

EPA-HQ-2018-002296

ATTACHMENT 4

Milestone Progress Payment Schedule

ED_002110_00032341-00088

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings	0.16	1.79
		NTE Load Diagrams		
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model	2.62	4.41
		Award Booster Fans		
6	Jul-17	NTE Load Diagrams	0.45	4.86
		Award Atomizers		
7	Aug-17	DFGD Supplier - Equipment Lists	6.24	11.10
		Award Lime System		
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information	0.45	12.00
		NTE Load Diagrams		
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages	2.68	22.36
		Flue Gas Ductwork Start of Fabrication		
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery	2.99	31.67
		Office Complex and Fabrication Areas Set-Up		
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery	5.12	36.79
		Lime Storage and Preparation System Delivery		
		Unit 1 Fabric Filter Delivery		
22	Nov-18	Unit 1 SDA Structural Steel Delivery	4.81	41.60
		Unit 1 Duct Delivery		
		Unit 1 SDA-A Support Steel Erection Complete		
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete	4.00	45.60
		Unit 1 Fabric Filter Structural Steel Delivery		
		Unit 2 Duct Delivery		
24	Jan-19	Unit 2 SDA Delivery	4.32	49.92
		Unit 1 SDA-A Inlet Duct Erection Complete		
		Unit 1 SDA-C Support Steel Erection Complete		
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete	4.08	54.00
		Unit 1 SDA-A Vessel Shell/Roof Complete		
		Unit 2 Fabric Filter Delivery		
26	Mar-19	Unit 2 Structural Steel Delivery	3.99	57.99
		Unit 1 SDA-B Inlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

EPA-HQ-2018-002296

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

ED_002110_00032341-00091

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

EPA-HQ-2018-002296

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

ED_002110_00032341-00093

Entergy Arkansas, Inc.

Entergy
White Bluff DGFD Project
Escalation Projections

SL-012831

Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

Misc Material and Equipment (Please see Note 1)									% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index									8%	15%	17.00%
Material Price, Construction Mat.									8%	7%	10.00%
Plant Cost Index									no increase	slightly negative	5.00%
Civil Work									8%	14%	15.00%
Steel - ductwork									no increase	slightly negative	8.00%
Steel - rolled shape									8%	no increase	10.00%
Architectural									5%	4%	8.00%
Overall mechanical equipment									4%	1%	7.00%
Overall piping									6%	11%	12.00%
Overall electrical equipment									9%	17%	18.00%
Raceway, Cable Tray, & Conduit									8%	slightly negative	10.00%
Electrical cable									14%	7%	15.00%
Controls & Instrumentation									1%	1%	5.00%
Average overall increase for Power back-fit projects									**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

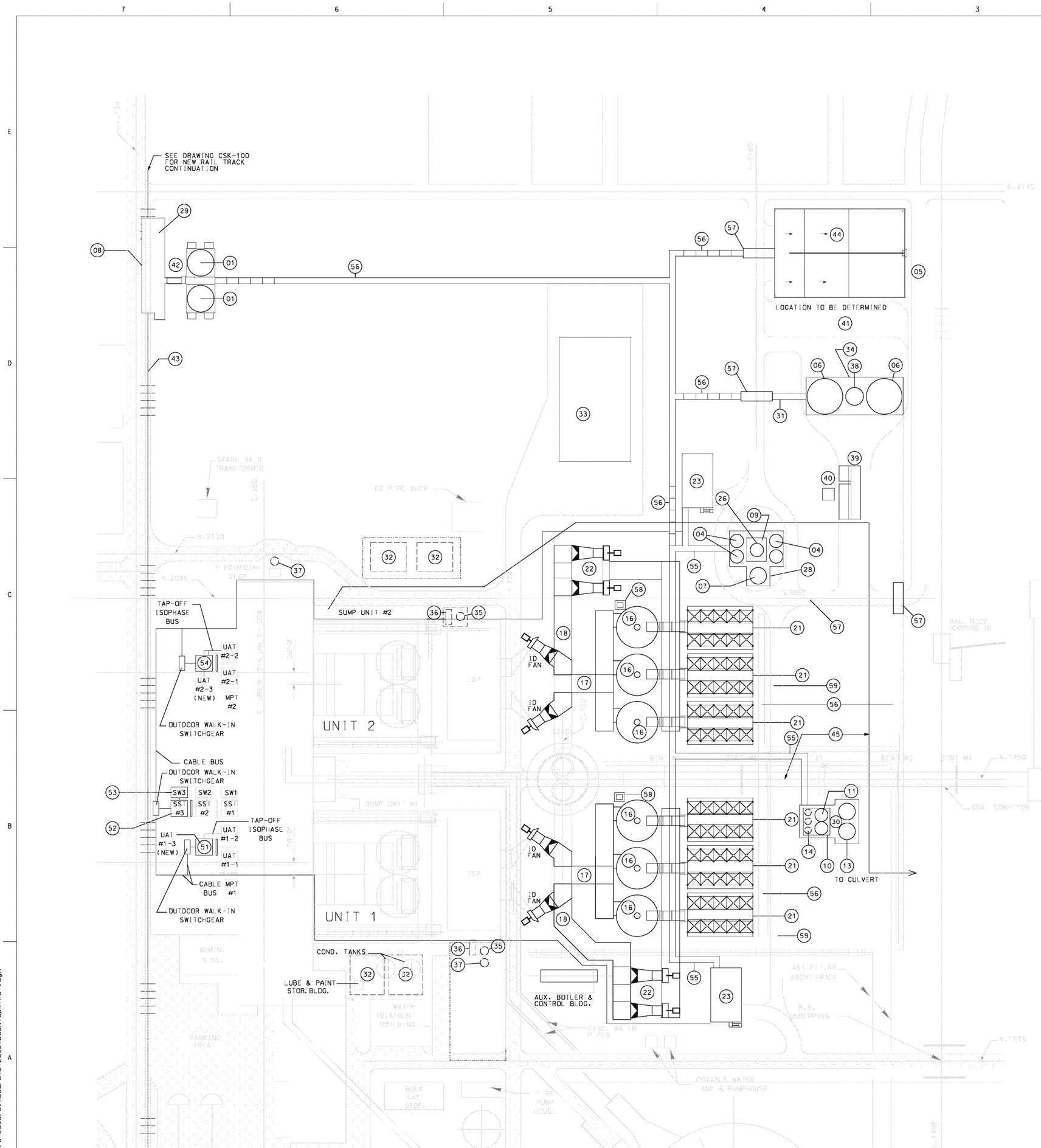
Sargent & Lundy

EPA-HQ-2018-002296

ATTACHMENT 7

Conceptual General Arrangement Drawing

ED_002110_00032341-00095



LEGEND

01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

PRELIMINARY
NOT FOR
CONSTRUCTION

NORTH

60′ 0 60′ 120′ 180′
GRAPHIC SCALE
DRAWING SCALE
1″ = 60′-0″

HOLD INFORMATION

NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: –

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

ZL8346/0-2695/C:*Users*0-2695*Desktop*TEST.dgn

5/28/2015 6:25:24 PM
...*Users*0-2695*Desktop*TEST.dgn

EPA-HQ-2018-002296

ATTACHMENT 8

Entergy Basis of Contingency

ED_002110_00032341-00097

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	$ 740,968,200				
	P90	P80	P70	P60	P50
Risk Contingency	$ 35,870,000	$ 27,220,000	$ 20,550,000	$ 16,210,000	$ 13,090,000
Estimate Uncertainty Contingency	$ 95,350,000	$ 66,600,000	$ 41,540,000	$ 21,330,000	$ (290,000)
Unknown Risk Contingency	$ 18,560,000	$ 17,380,000	$ 16,450,000	$ 15,610,000	$ 14,810,000
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			Resulting Range	
Estimate class	Maturity level of project definition expressed as % of complete engineering	End usage typical purpose of estimate	Methodology typical estimating method	Estimate accuracy range typical variation in low & high ranges	Target contingency range
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

WB FGD Project
Risk Register

ESTIMATE UNCERTAINTY							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project

Risk Register

UNKNOWN RISK							
Risk Category	Description of Risk	Quantitative Risk Analysis					Status / Comments
		Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

WB FGD Project

Risk Register

IDENTIFIED RISKS																	
				SCORING							Quantitative Risk Analysis						
Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project

Risk Register

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

Entergy

ENTERGY ARKANSAS, INC.

WHITE BLUFF

DSI COST ESTIMATE BASIS DOCUMENT

SL-014000
Final, Rev. 0
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

EPA-HQ-2018-002296

CONTENTS

Section **Page**

1. PURPOSE **1**

2. TECHNOLOGY DESCRIPTION **1**

3. APPROACH **2**

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS **5**

4.1 DESIGN INPUTS AND ASSUMPTIONS 5

4.1.1 ESP/Ash Handling Modifications 5

4.1.2 Landfill Modifications 7

4.2 TOTAL INSTALLED CAPITAL INVESTMENT 9

4.2.1 DSI Area (Single Unit) 9

4.2.2 Reagent Handling System 10

4.2.3 ESP/Ash Handling Modifications 11

4.2.4 Civil Work 11

4.2.5 Mechanical Work 11

4.2.6 Demolition/Relocation 11

4.2.7 Electrical 11

4.2.8 Instrumentation 11

4.2.9 Labor Costs 11

4.2.10 Other Direct and Construction Indirect Costs 12

4.2.11 EPC Indirect Costs 12

4.2.12 Owner's Costs and Services 13

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS 16

4.4 FIXED O&M COSTS 17

5. ATTACHMENTS **18**

ED_002110_00032341-00115

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of a new dry sorbent injection (DSI) system on the units at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3/NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, and injection lances.
- Reagent injection at the air preheater (APH) outlet, upstream of the existing ESP. The cost to rebuild/upgrade the ESP was included to ensure there is no increase in PM emissions as a significant quantity of reagent will be added upstream of the existing ESP.
- On-site disposal of DSI byproduct using upgraded ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the units; no additional blending equipment is required.
- Reagent injection rates based on 50% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
    - Annual operating costs will be based on 50% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
    - The system will be designed to control emissions to meet a permit limit of 0.35 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2014 through 2016.
- Trona was used as the DSI reagent for the purposes of this estimate.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference and mitigate potential for a brown plume.
- A high level conceptual system design, based on the estimated injection rate, was used as input to the DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional carbon consumption
    - Additional water consumption
    - Additional waste production
    - Reagent storage silos
    - Quantity of mills
    - Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34018A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of revenue from fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34018A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 50% (defined by injection rate, described in Section 4.1.1)
- Annual capacity factor of 71.2% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by rail.
- Existing activated carbon silo storage time will be reduced, rather than adding additional or larger storage silos to the system.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as impacts to the ESP performance, interference with mercury control technologies, and leachability of the byproduct.

4.1.1 ESP/Ash Handling Modifications

The DSI system, as defined in this report would require an estimated Trona injection rate of approximately 22,000 lb/hour to achieve 50% reduction at the design SO_2 inlet concentration. This injection rate would result in an increase in the particulate loading to the ESP of almost 40% from the current ash loading, due to the DSI byproducts and unreacted DSI reagent.

The addition of sodium compounds to the fly ash lowers the overall resistivity of the particulate being captured as well as shifting the particle size distribution. These changes have been shown to improve the removal efficiency of an ESP; in some cases this increase has been shown to offset the increased particulate loading to the ESP.

ESP performance can also be negatively impacted by a significant increase in particulate loading associated with the high reagent injection rates required for SO_2 control. It is uncertain whether modifications to the ESPs and ash handling systems would be required to accommodate the addition of DSI at White Bluff. However, at the very high injection rates expected for this project, an ESP rebuild will likely be required to ensure the PM emissions stay below the PSD threshold. Therefore, the capital cost estimate includes the costs to completely rebuild the existing ESPs and ash handling systems at White Bluff.

The size and condition of the existing ESP can play a critical role in the overall performance of DSI. In order to evaluate the existing White Bluff ESP with respect to future operation with DSI, S&L used the EPA program ESPVI 4.0W Performance Prediction Model (ESPVI 4.0W) to simulate the baseline and future operating scenarios, as described below. In addition, S&L contacted an ESP vendor to provide input relating to installation of DSI upstream of the existing ESPs at White Bluff.

The baseline operation was established using various design inputs for the units (as needed by the ESPVI 4.0W model), recent operating data and stack emissions to estimate the efficiency at which the ESP is currently operating. ESPVI 4.0W showed that at the baseline operating conditions the White Bluff ESP operates at approximately 99.7% removal of the total inlet loading, corresponding to a filterable PM emission limit of 0.0155 lb/MMBtu.

ESPs operate at a constant efficiency assuming the operating conditions (such as temperature, ash resistivity, or flue gas velocity) stay the same. DSI can impact some of the operating conditions, specifically ash resistivity and particle size distribution. The addition of DSI thus could result in a higher efficiency than the same ESP, without DSI, could achieve.

The ESPVI 4.0W model was developed prior to the introduction of DSI technology and has not been updated to account for the impacts of adding sorbents upstream of the ESP. However, the model was used to predict the high level impact and/or limitations of installing DSI technology by modifying some of the inputs to simulate the characteristics of a fly ash/sodium sorbent mixture.

Based on the modified ash resistivity and adjusted particle sizes associated with the addition of DSI, the baseline ESPVI 4.0W model was used to estimate the predicted removal efficiency for the White Bluff ESP with DSI, as defined in this report, and assuming all other operating

conditions remained the same. ESPVI 4.0W showed an overall removal efficiency which was very similar to the current ESP removal efficiency and resulted in an increase in particulate emissions with the additional loading from the DSI system.

Based on the results from ESPVI 4.0W, the White Bluff ESP may be operating at a marginally higher reduction efficiency with the installation of DSI; however, the loading to the ESP is also increasing significantly. Therefore, the modeling showed that even though the ESP efficiency may increase, the overall PM emissions will still be higher than the current level. This evaluation supports the conclusion that improvement of the existing ESP in conjunction with the DSI project is necessary to avoid increasing PM emissions.

In addition to the modeling that was performed using ESPVI 4.0W, S&L also engaged a vendor experienced with ESP retrofits to provide costs and expertise associated with injection of DSI on an existing ESP. As part of their budgetary quote, the supplier indicated that "while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr[1] will be extremely difficult to achieve the requested 0.015 lbs/MMBtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to 'as-new' condition with the most state-of-the-art technology options" (see Attachment 2).

Finally, in addition to the performance of the ESP, the increased loading will also have an impact on the ash handling system. Therefore, for the purposes of this cost estimate, based on the significant increase in loading, modifications to the ash handling equipment were included in the cost estimate.

4.1.2 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be

[1] The 73,000 lb/hr loading reflects the design fly ash loading plus the additional loading from the DSI injection (byproduct/unreacted sorbent).

present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
   - Twelve silos capable of storing approximately 14 days of sorbent per unit, 4,200-tons storage total, including substructure
   - 14' diameter and 125' high, each
   - 350-tons working storage, each
   - Continuous level detection systems
   - One bin vent filter per silo
   - Live bottom hopper outlets
   - Rotary airlock assemblies

b. Reagent conveying systems:
   - 4 trains (4 x 50%)
   - Pneumatic pressure blowers (1 x100% per train)
   - One dehumidifier and chiller per train

c. Reagent Milling
   - One 7-tph mill per train
   - One set of bypass piping per mill

d. Reagent Injection
   - Splitters with piping to two APH outlets
   - Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 165' x 125'

f. Buildings, enclosures, and roofs, including:
   - Blower Building, approximately 25' x 100'
   - Electrical Building; approximately 15' x 20'
   - Mill Building; approximately 40 x 80'
   - Dehumidifier Roof; approximately 30' x 125'
   - Heat Exchanger Roof; approximately 10' x 80'

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload two cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 20 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
   - System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
   - Enclosed railcar unloading building; approximately 200' x 75'
   - Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
   - Two trains (2 x 100%)
   - Pneumatic pressure blowers (1 x 100%) per train
   - One conveying air dehumidifier and chiller per train
   - Pneumatic conveying piping located on an above-grade sleeper pipe rack
   - The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 ESP/Ash Handling Modifications

a. ESP Rebuild – Based on the budgetary quote provided in Attachment 2.

b. Ash Handling Modifications – Equipment pricing based on recent vendor pricing for a similar project.

4.2.4 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.5 Mechanical Work

a. Allowance of $975,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.6 Demolition/Relocation

a. Allowance of $650,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.7 Electrical

a. Allowance of $3,575,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.8 Instrumentation

a. Allowance of $520,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.9 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.10 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime at five 10-hour shifts per week
d. Freight on construction materials
e. Contractor's General & Administration Fees (included at 10% of total direct costs)
f. Contractor's Profit (included at 5% of total direct costs)
g. Sales tax was included in the cost estimate at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.11 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $4,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $75,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $300,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.12 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day

cost. The total cost of the construction management support was estimated to be $1,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $300,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $1,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Activated Carbon	$/ton	$1,700
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Fly Ash Revenue	$/ton	$5.85
Aux Power Cost [1]	$/MWh	$41.02

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 1.3 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	16,500
Increased Carbon Consumption	lb/hr	210
DSI Waste Production + Increased Carbon + Unsold Fly Ash[3]	lb/hr	40,700
Aux Power Consumption	kW	1,700
Low Quality Water Consumption	gpm	4

	Units	Value
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$10,548,500
Waste Disposal Cost (DSI Waste + Increased Carbon + Unsold Fly Ash)	$/year	$951,900
Increased Carbon Consumption Cost	$/year	$1,113,000
Aux Power Cost	$/year	$434,900
Low Quality Water Cost	$/year	$800
Loss of Fly Ash Sales[3]	$/year	$496,000
Total First Year Variable O&M Cost	**$/year**	**$13,545,100**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 71.2%.

Note 3: Assumes 57% of the station's fly ash was being sold on an annual basis for an average of approximately $5.85 per ton (based on historical data from Entergy).

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.3% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance. Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$180,000
Maintenance Labor	$/year	$120,000
Total First Year Fixed O&M Cost	**$/year**	**$1,366,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34018A

2. ESP Rebuild Budgetary Quote

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34018A
Cost index	ARPBL

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	3,359,550	15,000,000	527,160	18,441	11,107,036	29,993,746
102	REAGENT HANDLING SYSTEM	1,565,400	1,360,000	1,218,523	26,467	1,956,963	6,040,885
103	ESP/ASH HANDLING MODIFICATIONS	50,000,000	1,050,000		9,885	680,982	51,730,982
104	EARTHWORK			79,496	2,169	183,755	263,251
105	UPGRADE PLANT ENTRANCE						
106	LAYDOWN AREAS			156,000	1,839	146,722	302,722
107	MECHANICAL MISCELLANEOUS	975,000					975,000
108	DEMOLITION / RELOCATION COSTS	650,000					650,000
109	ELECTRICAL	3,575,000					3,575,000
110	INSTRUMENTATION	520,000					520,000
	TOTAL DIRECT	**60,584,950**	**17,410,000**	**1,981,179**	**58,822**	**14,075,457**	**94,051,586**

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	14,075,457		58,822
Material	1,981,179		
Subcontract	60,584,950		
Process Equipment	17,410,000		
	94,051,586	94,051,586	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	985,000		
91-2 Cost Due To OT 5-10's	1,859,000		
91-4 Per Diem	588,000		
91-5 Consumables	141,414		
91-6 Freight on Material	99,000		
91-8 Sales Tax	2,384,000		
91-9 Contractors G&A	1,990,000		
91-10 Contractors Profit	994,000		
	9,040,414	103,092,000	
Indirect Costs:			
93-1 Engineering Services	4,000,000		
93-4 SU/S Parts/ Initial Fills	75,000		
93-5 Technical Field Advisors	300,000		
93-8 EPC Fee	10,747,000		
	15,122,000	118,214,000	
Escalation:			
96-1 Escalation on Material	137,000		
96-2 Escalation on Labor	1,693,000		
96-3 Escalation on Subcontract	5,238,000		
96-4 Escalation on Process Eq	926,000		
96-5 Escalation on Indirects	1,261,000		
	9,255,000	127,469,000	
Total EPC Cost		***127,469,000***	
Owner's Costs:			
99-1 Owner's Costs	9,457,000		
	9,457,000	136,926,000	
Third Party Services:			
100 CM Oversight	1,500,000		
101 Start-Up Oversight	300,000		
102 Owner's Engineer	1,750,000		
103 Performance Testing	175,000		
	3,725,000	140,651,000	
Project Contingency :			
110 Project Contingency	32,851,000		
	32,851,000	173,502,000	
Escalation Addition:			
120 Escalation on Lines 99-110	960,000		
	960,000	174,462,000	
Interest During Construction:			
130 Interest During Constr.	15,649,000		
	15,649,000	190,111,000	
Total		***190,111,000***	

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	323.00 EA	1,162,800	-	-		108.88 /MH		1,162,800
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			1,262,800						1,262,800
		21.98.00	CIVIL WORK, TESTING									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK, TESTING			65,000						65,000
			CIVIL WORK			1,327,800						1,327,800
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	2,292.00 CY	-	-	527,160	18,441	60.03 /MH	1,107,036	1,634,196
			CONCRETE					527,160	18,441		1,107,036	1,634,196
			CONCRETE					527,160	18,441		1,107,036	1,634,196
	23.00.00		STEEL									
		23.25.00	ROLLED SHAPE									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 100 FT	2,500.00 SF	500,000	-			93.00 /MH		500,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 15 FT X 20 FT	300.00 SF	105,000	-			93.00 /MH		105,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 40 FT X 80 FT	3,200.00 SF	640,000	-			93.00 /MH		640,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 125 FT	3,750.00 SF	318,750	-			93.00 /MH		318,750
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 80 FT	800.00 SF	68,000	-			93.00 /MH		68,000
			PRE-ENGINEERED BUILDING			1,631,750						1,631,750
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			1,631,750						1,631,750
	31.00.00		MECHANICAL EQUIPMENT									
		31.98.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		15,000,000	-		/MH	10,000,000	25,000,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				15,000,000				10,000,000	25,000,000
			MECHANICAL EQUIPMENT				15,000,000				10,000,000	25,000,000
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**3,359,550**	**15,000,000**	**527,160**	**18,441**		**11,107,036**	**29,993,746**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	UNLOADING SHED 200' X 75' WIDE	64.00 EA	230,400	-	-	0	108.88 /MH	1	230,401
			PILING			230,400			0		1	230,401
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			230,400		871,500	8,316		705,793	1,807,693
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75' WIDE	926.00 CY	-	-	212,980	7,451	60.03 /MH	447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75' WIDE x 20' TALL	15,000.00 SF	1,275,000	-			93.00 /MH		1,275,000
			PRE-ENGINEERED BUILDING			1,275,000						1,275,000
			ARCHITECTURAL			1,275,000						1,275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		2.00 LS	-	1,000,000	-	6,611	68.89 /MH	455,466	1,455,466
			MATERIAL HANDLING EQUIPMENT				1,000,000		6,611		455,466	1,455,466
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.89 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 200' X 75' WIDE	1.00 LT	-	135,000	-	1,862	93.00 /MH	173,172	308,172
			RAIL CAR UNLOADER				135,000		1,862		173,172	308,172
			MATERIAL HANDLING EQUIPMENT				1,360,000		8,474		628,638	1,988,638
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**1,505,400**	**1,360,000**	**1,218,523**	**26,487**		**1,956,963**	**6,040,885**
103			**ESP/ASH HANDLING MODIFICATIONS**									
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ESP EQUIPMENT MODIFICATION	FULL REBUILD OF ESP, INCLUDING INSTALLATION COST	1.00 LS	50,000,000	-	-		68.89 /MH		50,000,000

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ASH HANDLING COMPONENT MODIFICATION	ALLOWANCE	1.00 LS		1,050,000	-	9,885	68.89 /MH	680,982	1,730,982
			MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS			50,000,000	1,050,000		9,885		680,982	51,730,982
			MATERIAL HANDLING EQUIPMENT			50,000,000	1,050,000		9,885		680,982	51,730,982
			103 ESP/ASH HANDLING MODIFICATIONS			**50,000,000**	**1,050,000**		**9,885**		**680,982**	**51,730,982**
104			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING ALLOWANCE	30,000.00 SF	-	-		69	182.87 /MH	12,612	12,612
			STRIP & STOCKPILE TOPSOIL - ONSITE	BUILDINGS	600.00 CY	-	-		79	182.87 /MH	14,503	14,503
			STRIP & STOCKPILE TOPSOIL						148		27,115	27,115
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS	BUILDINGS	2,860.00 CY	-	-		986	79.78 /MH	78,680	78,680
			EXCAVATION						986		78,680	78,680
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING ALLOWANCE	1.00 LT	-	-	44,000	920	72.57 /MH	66,731	110,731
			STORM DRAINAGE UTILITIES					44,000	920		66,731	110,731
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING ALLOWANCE	3,333.00 SY	-	-	35,496	115	97.70 /MH	11,229	46,725
			EROSION AND SEDIMENTATION CONTROL					35,496	115		11,229	46,725
			CIVIL WORK					79,496	2,169		183,755	263,251
			104 EARTHWORK					**79,496**	**2,169**		**183,755**	**263,251**
105			**UPGRADE PLANT ENTRANCE**									
	21.00.00		CIVIL WORK									
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			UPGRADE PLANT ENTRANCE	WORK NOT REQUIRED	0.00 LF	-	-			78.79 /MH		
106			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	2.00 AC	-	-	156,000	1,839	79.78 /MH	146,722	302,722
			CIVIL WORK, MISCELLANEOUS					156,000	1,839		146,722	302,722
			CIVIL WORK					156,000	1,839		146,722	302,722
			106 LAYDOWN AREAS					**156,000**	**1,839**		**146,722**	**302,722**
107			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE SUBCONTRACT COST	1.00 LS	975,000	-	-		68.89 /MH		975,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			975,000						975,000
			MECHANICAL EQUIPMENT			975,000						975,000
			107 MECHANICAL MISCELLANEOUS			**975,000**						**975,000**
108			**DEMOLITION / RELOCATION COSTS**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	650,000	-			107.47 /MH		650,000
			DEMOLITION, MISCELLANEOUS			650,000						650,000
			DEMOLITION			650,000						650,000
			108 DEMOLITION / RELOCATION COSTS			**650,000**						**650,000**
109			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									

Estimate No.: 34018A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE - SUBCONTRACT COST	1.00 LS	3,575,000	-			64.04 /MH		3,575,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			3,575,000						3,575,000
			ELECTRICAL EQUIPMENT			3,575,000						3,575,000
			109 ELECTRICAL			**3,575,000**						**3,575,000**
110			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	520,000	-			65.15 /MH		520,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			520,000						520,000
			CONTROL & INSTRUMENTATION			520,000						520,000
			110 INSTRUMENTATION			**520,000**						**520,000**

27881 Clemens Road
Westlake, OH 44145
Phone: 440.899.3888
Fax: 440.899.3890

October 17, 2016

Sargent & Lundy
Attention: Danielle Flagg
55 East Monroe Street
Chicago, IL 60603

Subject: Fuel Tech, Inc. (FTI) Estimate #16-B-111 Rev1
Confidential Client ESP Retrofit
High Level Estimate

Dear Ms. Flagg,

In response to Sargent & Lundy's (S&L)'s recent request, Fuel Tech, Inc. (FTI), has assembled a high level estimate for the materials and installation necessary to retrofit Sargent & Lundy's "Confidential Client" Electrostatic Precipitators. Please consider the pricing as +/- 30% for high level budgetary estimation purposes.

The ESPs have been evaluated by our engineering staff and the estimate includes the most comprehensive improvements possible. Improvements that we have included in the estimate to increase performance and reliability include all new internals; collecting plates at 16" wide plate spacing, rigid discharge electrodes, top-rapped MIGI rapper conversion with increased rapping sectionalization, increased high voltage frame electrical sectionalization, and the addition of high frequency power supplies.

The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time. Thank you for your interest in our products and services, and we will continue to support Sargent & Lundy's efforts in any way practical for this and other opportunities. Should you require any additional information regarding this submittal, please contact me directly.

Respectfully,

Dustin Ekey
Regional Sales Manager

FTI Budgetary Proposal #16-B-111 Rev 1

Sargent & Lundy Confidential Client ESP Retrofit

Submitted by:

27881 Clemens Road
Westlake, Ohio 44145
P: 440.539.8792
www.ftek.com

EXECUTIVE SUMMARY

Sargent & Lundy – Confidential Client ESP Rebuild Budgetary Request:

In accordance with Sargent & Lundy's RFQ dated September 30, 2016, Fuel Tech, Inc. (FTI) has provided a high level estimate based on historical data to engineer, design, supply, and deliver an ESP Retrofit based on the provided information as follows;

A confidential client is currently evaluating the costs associated with rebuilding an existing ESP. As part of this project, the client will potentially be installing dry sorbent injection (DSI) upstream of the upgraded ESP.

The following summarizes the ESP design of the unit being evaluated:

- PC Walther original OEM installed in the early 1980s.
- Consists of four (4) identical ESP casings, with two (2) casings on top of the other two (2) casings; AKA "Piggybacked".
- Each ESP casing has eight (8) mechanical fields, two (2) mechanical fields wide by four (4) mechanical fields deep.
- Each field is 14' in length and contains forty-four (44) collecting electrodes with forty-three (43) gas passages.
- The collecting electrodes are 48' in height with 12" plate spacing.
- The total collecting surface area is 1,900,000 ft^2.
- Design flue gas flowrate is approximately 3,500,000 acfm, and a design velocity of 5 feet per second.
- The SCA of the existing ESP is approximately 540 ft^2/MMacfm.
- The overall dimension for each ESP is approximately 85'L x 90'W x 50'H.
- Each gas passage has discharge frame electrodes.
- The system is equipped with a Walther tumbling hammer rapper system.
- There are eight (8) T/R sets on each ESP, with a total of thirty-two (32).

ESP rebuild design and performance considerations:

- Achieve an outlet PM emissions rate of 0.015 lb/MMBtu or lower.
- Design inlet ash loading of 55,000 lb/hr.
- Non-halogenated PAC is injected at 150 lb/hr.
- Trona will be injected at 22,500 lb/hr, resulting in an increased particulate loading of 18,200 lb/hr to the ESP.
- Inlet flue gas temperature up to 315 deg F.

Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:

While the existing ESPs are considered to be relatively large by industry standards, the design information provided shows that 22,500 lb/hr of Trona will be injected in addition to the existing inlet ash loading is 55,000 lb/hr. With this being said, while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr will be extremely difficult to achieve the requested 0.015 lbs/MMbtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to "as-new" condition with the most state-of-the-art technology options. At the very least, new internals and electrical control systems would require new:

- Assembled Panel Collecting Electrodes
- Rigid Discharge Electrodes
- Top-Rapped MIGI Style Rapper Conversion
- All new Hot Roof, Cold Roof, and Penthouse
- Heated Purge Air Systems
- High Frequency Switch-Mode Power Supplies (SMPS)
- New Access Doors
- All new 3-Phase Electrical Supply Wiring
- New Controllers
- New Hopper Arrangement

Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:

Number of ESP's / Unit:	4
Mechanical Fields & Size / ESP:	6 @ 9'
Electrical Fields & Size / ESP:	12 @ 4.5'
Chambers / ESP:	2
Gas Passages / Chamber:	33
Collecting Plates / Chamber:	32
Collecting Plate Height:	44'
Plate Spacing:	16"
RDE's / ESP:	1,536
Rapping Arrangment:	Top Rapped – MIGI
Collecting System Rappers / ESP:	176
Discharge System Rappers / ESP:	48
High Frequency Power Supplies / ESP:	16

The amount of planning, engineering, material supply, installation, and installation oversight necessary for a project listed above will be very significant. Pricing estimation can be found below.

High-Level Pricing Estimation for one (1) Confidential Unit including all four (4) ESPs:

Pricing estimate is based upon +/- 30%

The total budgetary estimate to provide ESP materials and engineering: **$ 20,000,000.00**

The total budgetary estimate to provide non-union installation: **$ 30,000,000.00**

*Note: The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time.

Entergy

ENTERGY ARKANSAS, INC.

WHITE BLUFF

ENHANCED DSI COST ESTIMATE BASIS DOCUMENT

DRAFT

SL-014001
Final, Rev. 0
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

EPA-HQ-2018-002296

CONTENTS

Section **Page**

1. PURPOSE **1**

2. TECHNOLOGY DESCRIPTION **1**

3. APPROACH **2**

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS **5**

4.1 DESIGN INPUTS AND ASSUMPTIONS 5

4.1.1 Landfill Modifications 5

4.2 TOTAL INSTALLED CAPITAL INVESTMENT 6

4.2.1 DSI Area (Single Unit) 6

4.2.2 Reagent Handling System 7

4.2.3 Byproduct Handling 8

4.2.4 Baghouse Area 8

4.2.5 Ductwork and Supports 8

4.2.6 ID Booster Fans 9

4.2.7 Civil Work 9

4.2.8 Mechanical Work 9

4.2.9 Demolition/Relocation 9

4.2.10 Electrical 10

4.2.11 Instrumentation 10

4.2.12 Labor Costs 10

4.2.13 Other Direct and Construction Indirect Costs 10

4.2.14 EPC Indirect Costs 11

4.2.15 Owner's Costs and Services 11

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS 14

4.4 FIXED O&M COSTS 15

5. ATTACHMENTS **16**

DRAFT

ED_002110_00032341-00147

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of an enhanced dry sorbent injection (DSI) system utilizing a baghouse in conjunction with the DSI system at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of $SO_2$and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is considered a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP). The performance of DSI technology has been shown to be enhanced by implementation with a downstream fabric filter or baghouse. A baghouse increases the overall residence time due to longer ductwork and additional contact through the filter cake which builds up on the bags. The additional residence time improves performance and in some applications has resulted in much higher achievable removal efficiencies than traditional DSI technology upstream of an existing ESP.

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP or baghouse) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in a baghouse and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, injection lances, baghouse, and booster fans.
- Installation of a pulse jet fabric filter (PJFF) downstream of the existing ESPs to assist in SO_2 removal efficiency and capture of the DSI byproduct.
- Installation of new booster fans to account for increased draft pressure loss mainly due to the baghouse.
- Reagent injection at the ESP outlet, upstream of a new baghouse to collect flyash separately and preserve flyash sales
- On-site disposal of DSI byproduct, including flyash blending equipment for stabilization.
- Reagent injection rates based on 80% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
    - Annual operating costs will be based on 80% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
    - The system will be designed to control emissions to meet a permit limit of 0.15 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2009 through 2013.
- Trona was used as the DSI reagent for the purposes of this estimate.

DRAFT

- A high level conceptual system design, based on the estimated injection rate, was used as input to the Enhanced DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional carbon consumption
    - Additional water consumption
    - Additional waste production
    - Reagent storage silos
    - Quantity of mills
    - Quantity of blower trains

The fabric filter and ID fan equipment costs are scaled based on flue gas volume in comparison to industry data and recent budgetary cost estimates.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

DRAFT

Cost Estimate 34019A provided in Attachment 1 represents the total cost to Entergy to install Enhanced DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste)
- Reagent consumption
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- PJFF bag and cage replacement
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34019A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

DRAFT

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 80%
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the ESP outlet, upstream of the new baghouse.
- Reagent delivery by rail.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as leachability of the byproduct.

4.1.1 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

DRAFT

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The baghouse area equipment, ID fan equipment, and the remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
   - Twenty silos capable of storing approximately 14 days of sorbent per unit, 7,000-tons storage total, including substructure
   - 14' diameter and 125' high, each
   - 350-tons working storage, each
   - Continuous level detection systems
   - One bin vent filter per silo
   - Live bottom hopper outlets
   - Rotary airlock assemblies

b. Reagent conveying systems:
   - 5 trains (5 x 33%)
   - Pneumatic pressure blowers (1 x100% per train)
   - One dehumidifier and chiller per train

c. Reagent Milling
   - One 7-tph mill per train
   - One set of bypass piping per mill

d. Reagent Injection
   - Splitters with piping to two ESP outlets
   - Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 160' x 200'

f. Buildings, enclosures, and roofs, including:
   - Blower Building, approximately 25' x 125'
   - Electrical Building; approximately 30' x 20'
   - Mill Building; approximately 50' x 100'
   - Dehumidifier Roof; approximately 30' x 160'
   - Heat Exchanger Roof; approximately 10' x 100'

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload three cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 35 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
   - System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
   - Enclosed railcar unloading building; approximately 300' x 75'
   - Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
   - Three trains (3 x 100%)
   - Pneumatic pressure blowers (1 x 100%) per train
   - One conveying air dehumidifier and chiller per train

DRAFT

- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 Byproduct Handling

a. Two DSI by-product storage silos (approximately 7-day capacity) with bin vent filter, fluidizing system, and four unloading conditioners (pin mixers)

b. One common fly ash blending bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Concrete foundations including piles for silos

g. Continuous level detection system

h. One lot pneumatic conveying piping located on an above grade pipe rack

i. Two truck scales and substructure

j. Cost estimate based on a recent budgetary proposal for similar project

4.2.4 Baghouse Area

a. New baghouse, including pulse jet cleaning system and all appurtenances

b. Two casings with 8 compartments

c. 10 meter bags and cages

d. 6" insulation with lagging

e. Enclosure around hopper area

f. Baghouse area foundations including 18" auger cast piles 60' long

g. Equipment pricing based on recent pricing for similar projects

4.2.5 Ductwork and Supports

a. ID fan outlet to Baghouse inlet:

- Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new baghouse
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

DRAFT

b. Baghouse outlet to Booster fans
   - A single baghouse outlet duct which splits into two booster fan inlets.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

c. Booster fan outlet to the stack inlet ductwork and supports:
   - Two booster fan inlets, combine to a single duct which connects to the existing chimney breeching duct.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

d. Dampers and expansion joints

e. 6" insulation and lagging

f. Steel support structure and concrete mat foundations for all new flue gas ductwork

4.2.6 ID Booster Fans

a. Two, approximately 4,000 hp, axial booster fans sized to overcome pressure drop associated with baghouse

b. Includes motors - no spare motor included

c. Booster fan area foundations

4.2.7 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 4 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.8 Mechanical Work

a. Allowance of $2,600,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.9 Demolition/Relocation

a. Allowance of $975,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

DRAFT

4.2.10 Electrical

a. Allowance of $16,250,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.11 Instrumentation

a. Allowance of $2,210,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.12 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.13 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.14 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $10,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $150,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 200 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.15 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $2,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $350,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel

DRAFT

- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $2,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

DRAFT

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Low Quality Water	$/1000 gal	$0.53
Bag Cost [1]	$/bag	100.00
Cage Cost [1]	$/cage	30.00
Waste Disposal	$/ton	$7.50
Aux Power Cost [2]	$/MWh	$41.02

Note 1: Bags will be replaced every 3 years and cages will be replaced every 9 years.

Note 2: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 2.4 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	30,400
DSI Waste Production	lb/hr	24,100
Aux Power Consumption	kW	8,800
Low Quality Water Consumption	gpm	6
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$19,434,900
Waste Disposal Cost	$/year	$563,700
Aux Power Cost	$/year	$2,251,500
Low Quality Water Cost	$/year	$1,200
Bag and Cage Replacement Cost	$/year	$1,796,000
Total First Year Variable O&M Cost	**$/year**	**$24,047,300**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.5% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$645,000
Maintenance Labor	$/year	$430,000
Total First Year Fixed O&M Cost	**$/year**	**$2,141,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

DRAFT

5. ATTACHMENTS

1. White Bluff Station Enhanced DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34019A

DRAFT

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34019A
Cost index	ARPBL

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	4,693,000	20,500,000	817,880	28,611	15,417,548	41,428,428
102	REAGENT HANDLING SYSTEM	2,258,100	2,445,000	1,325,013	35,360	2,581,496	8,609,609
103	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	853,056	76,615	5,670,075	21,108,230
104	UNIT 1 OR 2 FLUE GAS SYSTEM	496,800	240,000	8,136,840	162,932	14,173,748	23,047,388
105	UNIT 1 OR 2 BOOSTER FANS		5,400,000	212,595	27,391	1,888,104	7,500,699
106	UNIT 1 OR 2 BAGHOUSE	1,173,600	20,000,000	3,638,113	85,175	19,008,734	43,820,447
107	EARTHWORK			2,021,832	44,398	5,879,245	7,901,077
108	LAYDOWN AREAS			312,000	3,678	293,444	605,444
109	MECHANICAL MISCELLANEOUS	2,600,000					2,600,000
110	DEMOLITION/RELOCATION	975,000					975,000
111	ACI RELOCATION	100,000		146,775	1,954	135,859	382,635
112	ELECTRICAL	16,250,000					16,250,000
113	INSTRUMENTATION	2,210,000					2,210,000
	TOTAL DIRECT	**38,469,600**	**55,457,000**	**17,464,103**	**466,134**	**65,048,253**	**176,438,956**

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	65,048,253		466,134
Material	17,464,103		
Subcontract	38,469,600		
Process Equipment	55,457,000		
	176,438,956	176,438,956	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	4,553,000		
91-2 Cost Due To OT 5-10's	8,760,000		
91-4 Per Diem	4,661,000		
91-5 Consumables	650,044		
91-6 Freight on Material	873,000		
91-8 Sales Tax	2,897,000		
91-9 Contractors G&A	10,350,000		
91-10 Contractors Profit	5,175,000		
	37,919,044	214,358,000	
Indirect Costs:			
93-1 Engineering Services	10,000,000		
93-4 SU/S Parts/ Initial Fills	150,000		
93-5 Technical Field Advisors	400,000		
93-8 EPC Fee	22,491,000		
	33,041,000	247,399,000	
Escalation:			
96-1 Escalation on Material	1,212,000		
96-2 Escalation on Labor	8,026,000		
96-3 Escalation on Subcontract	3,326,000		
96-4 Escalation on Process Eq	2,948,000		
96-5 Escalation on Indirects	2,756,000		
	18,268,000	265,667,000	
Total EPC Cost		***265,667,000***	
Owner's Costs:			
99-1 Owner's Costs	19,792,000		
	19,792,000	285,459,000	
Third Party Services:			
100 CM Oversight	2,500,000		
101 Start-Up Oversight	350,000		
102 Owner's Engineer	2,750,000		
103 Performance Testing	175,000		
	5,775,000	291,234,000	
Project Contingency :			
110 Project Contingency	68,242,000		
	68,242,000	359,476,000	
Escalation Addition:			
120 Escalation on Lines 99-110	1,893,000		
	1,893,000	361,369,000	
Interest During Construction:			
130 Interest During Constr.	32,375,000		
	32,375,000	393,744,000	
Total		***393,744,000***	

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Burgess & Lumby

Area	Group	Phase	Description	Notes	Quantity		Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate		Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**											
	21.00.00		CIVIL WORK											
		21.53.00	PILING											
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	500.00	EA	1,800,000	-	-		108.88	/MH		1,800,000
			PILE - MOB/DEMOB		1.00	LS	100,000	-			108.88	/MH		100,000
			PILING				1,900,000							1,900,000
		21.98.00	CIVIL WORK, TESTING											
			AUGER CAST GROUT PILE - TESTING		1.00	LS	65,000	-	-		-		-	65,000
			CIVIL WORK, TESTING				65,000							65,000
			CIVIL WORK				1,965,000							1,965,000
	22.00.00		CONCRETE											
		22.13.00	CONCRETE											
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	3,556.00	CY	-	-	817,880	28,611	60.03	/MH	1,717,548	2,535,428
			CONCRETE						817,880	28,611			1,717,548	2,535,428
			CONCRETE						817,880	28,611			1,717,548	2,535,428
	23.00.00		STEEL											
		23.25.00	ROLLED SHAPE											
			BUILDING MIX, TWO COAT PAINTED			TN	-	-			93.00	/MH		
	24.00.00		ARCHITECTURAL											
		24.35.00	PRE-ENGINEERED BUILDING											
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 125 FT	3,125.00	SF	625,000	-			93.00	/MH		625,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 30 FT X 20 FT	600.00	SF	210,000	-			93.00	/MH		210,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 50 FT X 100 FT	5,000.00	SF	1,000,000	-			93.00	/MH		1,000,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 160 FT	4,800.00	SF	408,000	-			93.00	/MH		408,000
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 100 FT	1,000.00	SF	85,000	-			93.00	/MH		85,000
			PRE-ENGINEERED BUILDING				2,328,000							2,328,000
		24.37.00	ROOFING											
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF		SF	-	-			35.25	/MH		
		24.41.00	SIDING											
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING		SF	-	-			79.98	/MH		
		24.99.00	ARCHITECTURAL, MISCELLANEOUS											
			HEATING	DSI AREA		SF	-	-			64.51	/MH		
			LIGHTING	DSI AREA		SF	-	-			82.56	/MH		
			FIRE PROTECTION	DSI AREA		SF	-	-			82.56	/MH		
			ARCHITECTURAL				2,328,000							2,328,000
	31.00.00		MECHANICAL EQUIPMENT											
		31.98.00	MECHANICAL EQUIPMENT, MISCELLANEOUS											
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00	LS		20,500,000	-			/MH	13,700,000	34,200,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			COMPRESSORS	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			FLOW MODELING	INCLUDED ABOVE	1.00	LS		-	-		68.89	/MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS					20,500,000					13,700,000	34,200,000
			MECHANICAL EQUIPMENT					20,500,000					13,700,000	34,200,000
	71.00.00		PROJECT INDIRECT											
		71.25.00	CONSULTANT, THIRD PARTY											
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00	LS	250,000	-				/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00	LS	150,000	-				/MH		150,000

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**4,693,000**	**20,500,000**	**817,880**	**28,611**		**15,417,548**	**41,428,428**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	UNLOADING SHED 300' X 75' WIDE	96.00 EA	345,600	-	-		108.88 /MH		345,600
			PILING			345,600						345,600
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			345,600		871,500	8,316		705,792	1,922,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 300' X 75' WIDE	1,389.00 CY	-	-	319,470	11,176	60.03 /MH	670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 300' X 75' WIDE x 20' TALL	22,500.00 SF	1,912,500	-			93.00 /MH		1,912,500
			PRE-ENGINEERED BUILDING			1,912,500						1,912,500
			ARCHITECTURAL			1,912,500						1,912,500
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		3.00 LS	-	1,500,000	-	9,917	68.89 /MH	683,199	2,183,199
			MATERIAL HANDLING EQUIPMENT				1,500,000		9,917		683,199	2,183,199
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	3.00 EA	-	675,000	-		68.89 /MH		675,000
			MOBILE YARD EQUIPMENT				675,000					675,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 300' X 75' WIDE	2.00 LT	-	270,000	-	3,724	93.00 /MH	346,345	616,345
			RAIL CAR UNLOADER				270,000		3,724		346,345	616,345
			MATERIAL HANDLING EQUIPMENT				2,445,000		13,641		1,029,544	3,474,544
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**2,258,100**	**2,445,000**	**1,325,013**	**35,380**		**2,581,496**	**8,609,609**
103			**BYPRODUCT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND DSI BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.88 /MH	344,161	576,286
			CAISSON					232,125	3,161		344,161	576,286

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					232,125	3,161		344,161	576,286
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	DSI BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	60.03 /MH	296,562	437,782
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	60.03 /MH	32,361	47,771
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	60.03 /MH	69,552	102,672
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	60.03 /MH	48,300	71,300
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					214,130	7,491		449,673	663,803
			CONCRETE					214,130	7,491		449,673	663,803
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.51 /MH	208,701	483,701
			SILO				275,000		2,839		208,701	483,701
			STEEL				275,000		2,839		208,701	483,701
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	93.00 /MH	10,690	20,690
			PRE-ENGINEERED BUILDING					10,000	115		10,690	20,690
			ARCHITECTURAL					10,000	115		10,690	20,690
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - DSI BYPRODUCT SILO	ERECTED - 52' DIA	2.00 LS	7,600,000				60.03 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.51 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.51 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.51 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	51,910	73.51 /MH	3,815,929	3,815,929
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.51 /MH		
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.51 /MH	18,977	78,977
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.51 /MH	50,595	130,595
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.51 /MH	246,047	786,047
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		56,204		4,131,549	10,466,549
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.89 /MH	31,674	213,674
			SCALE				182,000		460		31,674	213,674
			MATERIAL HANDLING EQUIPMENT				6,517,000		56,664		4,163,223	10,680,223
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.51 /MH		113,100
			DUST COLLECTOR			113,100						113,100

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	2,500.00 LF	-	-	248,000	3,966	77.80 /MH	308,517	556,517
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.80 /MH	185,110	333,910
			CARBON STEEL, STRAIGHT RUN					396,800	6,345		493,628	890,428
			PIPING					396,800	6,345		493,628	890,428
			103 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**853,055**	**76,615**		**5,670,075**	**21,108,230**
104			**UNIT 1 OR 2 FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		138.00 EA	496,800	-	-		108.88 /MH		496,800
			PILING			496,800						496,800
			CIVIL WORK			496,800						496,800
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE		966.00 CY	-	-	222,180	7,772	60.03 /MH	466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES		867.40 TN	-	-	2,819,050	59,821	97.70 /MH	5,844,481	8,663,531
			DUCTWORK					2,819,050	59,821		5,844,481	8,663,531
		23.21.00	GIRDER									
			ROLLED SHAPE STEEL		1,308.00 TN	-	-	3,544,680	45,103	93.00 /MH	4,194,621	7,739,301
			GIRDER					3,544,680	45,103		4,194,621	7,739,301
			STEEL					6,363,730	104,924		10,039,102	16,402,832
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES		800.00 SF	-	240,000		1,471	97.70 /MH	143,743	383,743
			DAMPERS & ACCESSORIES				240,000		1,471		143,743	383,743
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINTS		1,830.00 LF	-		457,500	5,259	97.70 /MH	513,767	971,267
			EXPANSION JOINT					457,500	5,259		513,767	971,267
			MECHANICAL EQUIPMENT				240,000	457,500	6,730		657,510	1,355,010
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE		168,220.00 SF	-	-	1,093,430	43,505	69.20 /MH	3,010,558	4,103,988
			DUCT					1,093,430	43,505		3,010,558	4,103,988
			INSULATION					1,093,430	43,505		3,010,558	4,103,988
			104 UNIT 1 OR 2 FLUE GAS SYSTEM			**496,800**	**240,000**	**8,136,840**	**162,932**		**14,173,748**	**23,047,388**
105			**UNIT 1 OR 2 BOOSTER FANS**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON		40.00 EA	-	-	74,280	1,011	108.88 /MH	110,131	184,411
			CAISSON					74,280	1,011		110,131	184,411
			CIVIL WORK					74,280	1,011		110,131	184,411
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE		600.00 CY	-	-	138,000	4,828	60.03 /MH	289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
	31.00.00		MECHANICAL EQUIPMENT									
		31.35.00	FANS & ACCESSORIES (EXCL HVAC)									
			BOOSTER FAN 1.8 MACFM, 4000 HP MOTOR		2.00 EA	-	5,400,000	-	10,345	68.89 /MH	712,655	6,112,655
			FANS & ACCESSORIES (EXCL HVAC)				5,400,000		10,345		712,655	6,112,655
			MECHANICAL EQUIPMENT				5,400,000		10,345		712,655	6,112,655
	36.00.00		INSULATION									
		36.15.00	EQUIPMENT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED ON GROUND		1,500.00 SF	-	-	315	11,207	69.20 /MH	775,517	775,832
			EQUIPMENT					315	11,207		775,517	775,832
			INSULATION					315	11,207		775,517	775,832
			105 UNIT 1 OR 2 BOOSTER FANS				**5,400,000**	**212,595**	**27,391**		**1,888,104**	**7,500,699**
106			**UNIT 1 OR 2 BAGHOUSE**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		326.00 EA	1,173,600	-	-		108.88 /MH		1,173,600
			PILING			1,173,600						1,173,600
			CIVIL WORK			1,173,600						1,173,600
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE		2,260.00 CY	-	-	519,800	18,184	60.03 /MH	1,091,580	1,611,380
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					521,180	18,232		1,094,478	1,615,658
			CONCRETE					521,180	18,232		1,094,478	1,615,658
	23.00.00		STEEL									
		23.25.00	ROLLED SHAPE									
			BUILDING MIX, GALVANIZED	UNIT 1 BAGHOUSE	560.00 TN	-	-	1,534,400	10,299	93.00 /MH	957,793	2,492,193
			ROLLED SHAPE					1,534,400	10,299		957,793	2,492,193
			STEEL					1,534,400	10,299		957,793	2,492,193
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	93.00 /MH	10,690	30,690
			PRE-ENGINEERED BUILDING					20,000	115		10,690	30,690
		24.41.00	SIDING									
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	BAGHOUSE SKIRTS	68,112.00 SF	-	-	221,364	3,210	79.98 /MH	256,726	478,090
			SIDING					221,364	3,210		256,726	478,090
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			MISCELLANEOUS	BAGHOUSE SKIRTS MANDOORS	4.00 EA	-	-	2,000	37	51.46 /MH	1,893	3,893
			ARCHITECTURAL, MISCELLANEOUS					2,000	37		1,893	3,893
			ARCHITECTURAL					243,364	3,362		269,308	512,672
	31.00.00		MECHANICAL EQUIPMENT									
		31.57.00	PARTICULATE REMOVAL									
			BAGHOUSE SYSTEM - INCLUDES PENTHOUSE, BYPASS, DAMPERS, EXP. JOINTS, TUBESHEETS, BAGS, CAGES, CLEANING PIPING, VALVES, BLOWERS, ETC.		1.00 LS	-	20,000,000	-		/MH	13,000,000	33,000,000
			PARTICULATE REMOVAL				20,000,000				13,000,000	33,000,000
			MECHANICAL EQUIPMENT				20,000,000				13,000,000	33,000,000
	36.00.00		INSULATION									
		36.13.00	DUCT									

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	206,026.00 SF	-	-	1,339,169	53,283	69.20 /MH	3,687,155	5,026,324
			DUCT					1,339,169	53,283		3,687,155	5,026,324
			INSULATION					1,339,169	53,283		3,687,155	5,026,324
			106 UNIT 1 OR 2 BAGHOUSE			**1,173,600**	**20,000,000**	**3,638,113**	**85,175**		**19,008,734**	**43,820,447**
107			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.87 /MH	252,234	252,234
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.87 /MH	3,867,595	3,867,595
			STRIP & STOCKPILE TOPSOIL						22,529		4,119,830	4,119,830
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		20,917.00 CY	-	-		7,213	79.78 /MH	575,434	575,434
			EXCAVATION						7,213		575,434	575,434
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.57 /MH	166,828	276,828
			STORM DRAINAGE UTILITIES					110,000	2,299		166,828	276,828
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.70 /MH	224,599	934,602
			EROSION AND SEDIMENTATION CONTROL					710,004	2,299		224,599	934,602
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.79 /MH	633,943	1,133,943
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.79 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.79 /MH	158,612	360,440
			ROAD, PARKING AREA, & SURFACED AREA					1,201,828	10,059		792,555	1,994,383
			CIVIL WORK					2,021,832	44,398		5,879,245	7,901,077
			107 EARTHWORK					**2,021,832**	**44,398**		**5,879,245**	**7,901,077**
108			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	4.00 AC	-	-	312,000	3,678	79.78 /MH	293,444	605,444
			CIVIL WORK, MISCELLANEOUS					312,000	3,678		293,444	605,444
			CIVIL WORK					312,000	3,678		293,444	605,444
			108 LAYDOWN AREAS					**312,000**	**3,678**		**293,444**	**605,444**
109			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE	1.00 LS	2,600,000	-	-		68.89 /MH		2,600,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			2,600,000						2,600,000
			MECHANICAL EQUIPMENT			2,600,000						2,600,000
			109 MECHANICAL MISCELLANEOUS			**2,600,000**						**2,600,000**
110			**DEMOLITION/RELOCATION**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE	1.00 LS	975,000	-			107.47 /MH		975,000
			DEMOLITION, MISCELLANEOUS			975,000						975,000
			DEMOLITION			975,000						975,000
			110 DEMOLITION/RELOCATION			**975,000**						**975,000**
111			**ACI RELOCATION**									
	22.00.00		CONCRETE									

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	30.00 CY	-	-	6,900	241	60.03 /MH	14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	364.00 SF	-	-	5,460	42	66.40 /MH	2,778	8,238
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	218.00 LF	-	-	11,554	45	66.40 /MH	2,995	14,549
			STAIR SYSTEM -	ACI PORT STAIR TOWERS AND PLATFORMS	448.00 SF	-	-	40,768	592	66.40 /MH	39,321	80,089
			GALLERY					57,782	679		45,094	102,876
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	93.00 /MH	2,290	5,704
			GIRDER					3,415	25		2,290	5,704
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 1 TOWER	2.20 TN	-	-	7,876	56	93.00 /MH	5,174	13,050
			ROLLED SHAPE					7,876	56		5,174	13,050
			STEEL					69,073	759		52,558	121,630
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	1.00 EA	-	-	-	69	68.89 /MH	4,751	4,751
			CRANES & HOISTS						69		4,751	4,751
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	16.00 EA	-	-	-	184	68.89 /MH	12,669	12,669
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	2.00 EA	-	-	40,000	92	68.89 /MH	6,335	46,335
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	1.00 EA	-	-	-	11	68.89 /MH	792	792
			MERCURY REMOVAL EQUIPMENT					40,000	287		19,796	59,796
			MECHANICAL EQUIPMENT					40,000	356		24,547	64,547
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	6.00 LF	-	-	176	3	77.80 /MH	220	396
			2 IN DIA, TAPER	INJECTION PORTS	8.00 LF	-	-	210	5	77.80 /MH	351	561
			3 IN DIA, TAPER	INJECTION PORTS	20.00 LF	-	-	516	15	77.80 /MH	1,198	1,714
			FRP, ABOVE GROUND, PROCESS AREA					903	23		1,769	2,672
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	300.00 LF	-	-	6,330	200	77.80 /MH	15,560	21,890
			FRP, STRAIGHT RUN					6,330	200		15,560	21,890
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	13.50 EA	-	-	41	31	77.80 /MH	2,414	2,455
			SUPPORT SLEEPERS	ACI PIPE	8.50 EA	-	-	2,975	39	77.80 /MH	3,040	6,015
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		1.00 EA	-	-	153	9	77.80 /MH	715	868
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	288	16	77.80 /MH	1,252	1,540
			PIPE SUPPORTS, RACK					3,457	95		7,422	10,879
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	4.00 EA	-	-	80	33	77.80 /MH	2,575	2,655
			VALVES					80	33		2,575	2,655
			PIPING					10,769	351		27,327	38,096
	41.00.00		ELECTRICAL EQUIPMENT									
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									

Estimate No.: 34019A
Project No.: 13027-004
Estimate Date: 10/20/2016
Prep/Rev/App: A. KOCI/MNO/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	2.00 EA	-	-	9,800	37	64.04 /MH	2,355	12,155
			MOTOR CONTROL CENTER (MCC), COMPONENT					9,800	37		2,355	12,155
			ELECTRICAL EQUIPMENT					9,800	37		2,355	12,155
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	2.00 EA	-	-	172	3	62.27 /MH	179	351
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					172	3		179	351
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	225.00 LF	-	-	659	50	62.27 /MH	3,124	3,783
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	200.00 LF	-	-	1,344	65	62.27 /MH	4,065	5,409
			CONDUIT, RGS					2,003	115		7,190	9,193
			RACEWAY, CABLE TRAY & CONDUIT					2,175	118		7,369	9,544
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	300.00 LF	-	-	960	28	82.56 /MH	2,278	3,238
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					960	28		2,278	3,238
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	250.00 LF	-	-	1,640	7	82.56 /MH	593	2,233
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	225.00 LF	-	-	5,364	36	82.56 /MH	2,989	8,353
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	6.00 EA	-	-	39	2	82.56 /MH	171	210
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	6.00 EA	-	-	56	3	82.56 /MH	285	340
			600V CABLE & TERMINATION					7,099	49		4,038	11,136
			CABLE					8,059	76		6,315	14,374
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	3.00 EA	-	-		14	65.15 /MH	899	899
			INSTRUMENT						14		899	899
			CONTROL & INSTRUMENTATION						14		899	899
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			111 ACI RELOCATION			**100,000**		**146,775**	**1,954**		**135,859**	**382,635**
112			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE	1.00 LS	16,250,000	-			64.04 /MH		16,250,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			16,250,000						16,250,000
			ELECTRICAL EQUIPMENT			16,250,000						16,250,000
			112 ELECTRICAL			**16,250,000**						**16,250,000**
113			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE	1.00 LS	2,210,000	-			65.15 /MH		2,210,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			2,210,000						2,210,000
			CONTROL & INSTRUMENTATION			2,210,000						2,210,000
			113 INSTRUMENTATION			**2,210,000**						**2,210,000**

APPENDIX B. BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	40.38 lb/hr	(PMC)
Fine Soil	31.11 lb/hr	(PMF)
Fine EC	1.20 lb/hr	(EC)
CPM OR	9.31 lb/hr	(SOA)
CMP IOR	5.11 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 44,739.30 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 172,605.31 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 29,661.00 tons/yr (max day during 2014-2016)	Entergy CAMD data
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	40.38 lb/hr	(PMC)
Fine Soil	31.11 lb/hr	(PMF)
Fine EC	1.20 lb/hr	(EC)
CPM OR	9.31 lb/hr	(SOA)
CMP IOR	4.99 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 43,750.51 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 168,790.55 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 29,005.46 tons/yr (max day during 2014-2016)	Entergy CAMD data
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	40.38 lb/hr	(PMC)
Fine Soil	31.11 lb/hr	(PMF)
Fine EC	1.20 lb/hr	(EC)
CPM OR	9.31 lb/hr	(SOA)
CMP IOR	4.05 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 35,477.40 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 136,872.70 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 23,520.60 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	40.38 lb/hr	(PMC)
Fine Soil	31.11 lb/hr	(PMF)
Fine EC	1.20 lb/hr	(EC)
CPM OR	9.31 lb/hr	(SOA)
CMP IOR	4.05 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 35,477.40 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 136,872.70 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 23,520.60 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	29.04 lb/hr	(PMC)
Fine Soil	22.37 lb/hr	(PMF)
Fine EC	0.86 lb/hr	(EC)
CPM OR	13.40 lb/hr	(SOA)
CMP IOR	0.47 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 20,695.15 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 79,842.41 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 13,720.35 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 20,695.15 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 4,139.03 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	29.04 lb/hr	(PMC)
Fine Soil	22.37 lb/hr	(PMF)
Fine EC	0.86 lb/hr	(EC)
CPM OR	13.40 lb/hr	(SOA)
CMP IOR	0.47 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 20,695.15 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 79,842.41 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 13,720.35 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
$TSAR_{ALKINJ}$ = $(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 20,695.15 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 4,139.03 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	13.37 lb/hr	(PMC)
Fine Soil	12.87 lb/hr	(PMF)
Fine EC	0.49 lb/hr	(EC)
CPM OR	18.59 lb/hr	(SOA)
CPM IOR	0.02 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= {[(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] * $F2_{APH}$ + ($EM_{FGC_afterAPH}$ - $NH3_{FGC_afterAPH}$)} * $F2_X$	4-11 (Eqn 4-10)
= 886.94 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 34,218.18 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 5,880.15 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= K_e * B * f_e * I_s * $F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= K_e * B * f_e * I_{NH3} $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
= 0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)	4-20 (Table 4-4)
= 0.072 product of all factors	
$TSAR_{ALKINJ}$ = ($TSAR_{Comb+SCR+FGC}$) * $F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 886.94 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 177.39 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_3 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	13.37 lb/hr	(PMC)
Fine Soil	12.87 lb/hr	(PMF)
Fine EC	0.49 lb/hr	(EC)
CPM OR	18.59 lb/hr	(SOA)
CPM IOR	0.02 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= {[(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] * $F2_{APH}$ + ($EM_{FGC_afterAPH}$ - $NH3_{FGC_afterAPH}$)} * $F2_X$	4-11 (Eqn 4-10)
= 886.94 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 34,218.18 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 5,880.15 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= K_e * B * f_e * I_s * $F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= K_e * B * f_e * I_{NH3} $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
= 0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)	4-20 (Table 4-4)
= 0.072 product of all factors	
$TSAR_{ALKINJ}$ = ($TSAR_{Comb+SCR+FGC}$) * $F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$ = 886.94 lb/year	
$F3_{ALKINJ}$ = 0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
= 177.39 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_3 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	13.37 lb/hr	(PMC)
Fine Soil	12.87 lb/hr	(PMF)
Fine EC	0.49 lb/hr	(EC)
CPM OR	18.50 lb/hr	(SOA)
CMP IOR	0.01 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= {[(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] * $F2_{APH}$ + ($EM_{FGC_afterAPH}$ - $NH3_{FGC_afterAPH}$)} * $F2_x$	4-11 (Eqn 4-10)
= 49.27 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 13,687.27 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 2,352.06 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= K_e * B * f_e * I_s * $F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC_beforeAPH}$)] is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= K_e * B * f_e * I_{NH3} $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.01 for dry FGD and baghouse	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	13.37 lb/hr	(PMC)
Fine Soil	12.87 lb/hr	(PMF)
Fine EC	0.49 lb/hr	(EC)
CPM OR	18.50 lb/hr	(SOA)
CMP IOR	0.01 lb/hr	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	Page Reference
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})] * F2_{APH} + (EM_{FGC_afterAPH} - NH3_{FGC_afterAPH})\} * F2_X$	4-11 (Eqn 4-10)
= 49.27 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 13,687.27 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 2,352.06 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC_beforeAPH}) - (NH3_{SCR} + NH3_{FGC_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ $NH3_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *77.87*	*see above*
f_e = *0 unitless*	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.01 for dry FGD and baghouse	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

Entergy Arkansas Inc.

Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 7, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov
Docket ID No. EPA-R06-OAR-2015-0189

TABLE OF CONTENTS

I. INTRODUCTION 1

II. EXECUTIVE SUMMARY 1

III. COMMENTS 5

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan. 5

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis. 5

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff. 7

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART. 11

4. Emissions reductions at White Bluff will be achieved through interim controls. 13

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes. 14

1. EPA's reasonable progress analysis does not follow prior actions. 14

2. EPA is obliged to act consistently in promulgating rules. 17

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time. 17

1. Controls on Independence do not further the goal of the Regional Haze Program. 18

2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress. 32

3. The proposed controls are not cost effective. 43

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence. 45

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress. 45

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less. 45

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal. 49

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions. 49

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls. 52

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated. 52

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4. 53

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas. 54

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211 55

I. Additional Comments. 56

IV. CONCLUSION 57

EXHIBITS

A. *Review of EPA's Cost Analysis for Arkansas Regional Haze Proposed Federal Implementation Plan*, Report No. SL-012913, Sargent & Lundy (July 2015).

B. *White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015).

C. *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant*, Trinity Consultants (August 4, 2015).

D. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015).

E. *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Management Association (2002).

F. Excerpts from *Tangential Low NOx (TLN3) System for Entergy White Bluff Units 1 & 2*, Foster Wheeler North America Corp. Proposal to Entergy (Oct. 13, 2011).

G. Memorandum from Steve deMello, Project Manager, Amec Foster Wheeler North America Corp., to Michael P. Fallon, P.E., Entergy (July 30, 2015).

H. *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015).

I. Entergy Arkansas Inc.'s Comments on the Proposed Approval and Promulgation of Implementation Plans; Interstate Transport State Implementation Plan; Arkansas, Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility, Docket No. EPA-R06-OAR-2008-0633.

ENTERGY ARKANSAS INC. COMMENTS ON THE PROPOSED REGIONAL HAZE AND INTERSTATE VISIBILITY TRANSPORT FEDERAL IMPLEMENTATION PLAN FOR ARKANSAS

EPA-R06-OAR-2015-0189

I. INTRODUCTION

On April 8, 2015, the U. S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 18,944, a proposed Federal Implementation Plan ("FIP") to address certain regional haze and visibility transport requirements for the State of Arkansas ("Proposed FIP" or "Proposal"). The Proposed FIP would address the requirements of the Regional Haze Rule and interstate visibility transport for those portions of Arkansas' State Implementation Plan ("SIP") that EPA previously had disapproved. *See* 77 Fed. Reg. 14,604 (Mar. 12, 2012). The Proposed FIP addresses the requirements for Best Available Retrofit Technology ("BART") for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals ("RPGs"), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") BART limits for White Bluff Units 1 and 2, and SO_2, NOx, and particulate matter ("PM") BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NOx BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NOx emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

In these comments, Entergy discusses its legal and technical concerns with the Proposed FIP. Entergy appreciates EPA's consideration of these comments, and urges EPA to make Entergy's suggested changes and issue a final FIP that provides visibility benefits without overly burdening EAI's customers and co-owners.

II. EXECUTIVE SUMMARY

The Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the Clean Air Act ("CAA") as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to

recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's Proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on EAI's customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Entergy proposes a more reasonable, long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. In particular, Entergy proposes the following: (1) to achieve early SO_2 reductions by accepting lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to achieve NOx reductions by installing NOx control technology on all four units within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff by 2028. Based on modeling by Entergy (which EPA should have conducted but failed to undertake), the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small (*see* Section III.D.2 below) and does not warrant an investment of over $2 billion in scrubber technology at the plants.

Entergy's comments address a range of issues raised by the Proposal. Two issues are most critical. First, with respect to White Bluff, Entergy proposes to cease all coal-fired operations at the two coal-fired units in 2027 and 2028. This proposal necessarily changes the BART analysis for White Bluff. Because of Entergy's proposed commitment to stop burning coal, EPA's proposal to establish BART limits for White Bluff based on the installation of dry flue gas desulfurization ("FGD" or "scrubbers") must be rejected. Under the current schedule for finalizing the FIP, the scrubbers would not be installed until at least 2021, which would leave only six to seven years for EAI to recoup the approximately $1 billion in investment for dry scrubber installation. That cannot be justified economically or environmentally. Economically, the short amortization period would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Environmentally, EPA projects that visibility will improve in each of Arkansas' Class I areas only by approximately one-fifth of a deciview ("dv") as a result of the proposed FIP controls on all sources in Arkansas; an amount that is absolutely undetectable. Controls on White Bluff would achieve merely a fraction of that amount.

Second, EPA's proposal to require SO_2 and NOx limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first planning period. Independence is not a BART-eligible source.[1] Accordingly, EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I

[1] Despite the fact that Independence is not a BART-eligible source under the Clean Air Act, EPA's analysis in the Proposal essentially and improperly treated it as such.

areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[2] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. *See* Section III.C.3 below. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[3]

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment ("IMPROVE") data, which reflects monitored visibility impairment in Class I areas, the haze index for the 20% worst ("W20") days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association ("CENRAP"),[4] all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[5] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

---

[2] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[3] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

[4] CENRAP is a regional planning organization that includes nine states – Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[5] In spite of the Supreme Court decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units ("EGUs"), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, Entergy expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. *See* Section III.D.2 below (Figures 13 and 14). Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine reasonable progress goals. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EAI's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term. Entergy proposes to meet more stringent SO_2 limits at both White Bluff and Independence beginning in 2018. In addition, Entergy proposes to install low NOx burners ("LNB") and separated overfire air ("SOFA") on both White Bluff and Independence within three years of the final FIP's effective date, assuring that there will be both near-term and long-term visibility benefits.

III. COMMENTS

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan.

EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to the Arkansas Department of Environmental Quality ("ADEQ") in October 2013 ("Revised White Bluff BART Analysis"),[6] which assumed White Bluff Units 1 and 2 would continue to combust coal for the foreseeable future. As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect.[7]

As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

The CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

---

[6] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969. The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[7] Entergy anticipates that its compliance with a final FIP, including installing dry scrubbers or, in the alternative, ceasing coal-fired operation at White Bluff, will be subject to Arkansas Public Service Commission hearing and review.

Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

BART controls that may be cost effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost effectiveness at Unit 1 of $2,227/ton and at Unit 2 of $2,101/ton. 80 Fed. Reg. at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[8]

Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[9] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[10] In light of Entergy's proposed commitment to cease coal-fired operations at the units in 2027 and 2028, the amortization period will be approximately six to seven years. This has a significant impact on the cost calculation, resulting in much higher costs compared to the emissions reductions achieved.

[8] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[9] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[10] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff.

EPA's analysis of the cost and cost effectiveness of installing dry scrubbers at White Bluff contains numerous flawed methodologies, incorrect assumptions and mistakes, all of which seem designed to artificially lower the actual costs of installing dry scrubbers and improve the supposed cost effectiveness of the controls. Sargent & Lundy ("S&L") has undertaken a thorough analysis of EPA's SO_2 Cost TSD and provided a report, *Report of EPA's Cost Analysis Arkansas Regional Haze Proposed Federal Implementation Plan*, No. SL-012913, Sargent & Lundy (July 2015) ("S&L FIP Cost Report") (attached as Exhibit A and incorporated by reference herein). The S&L FIP Cost Report demonstrates that EPA incorrectly specified the SO_2 emissions baseline for White Bluff, which increased expected emissions. EPA then improperly used maximum monthly emissions to estimate the tonnage reduction achievable with the scrubbers to reduce the cost per ton, and incorrectly eliminated approximately $100 million in costs that EPA's own Control Cost Manual says should be included.

(i) EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id.* The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

(ii) EPA uses an incorrect methodology that artificially inflates the SO_2 emission reductions achievable with scrubbers.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015-0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id.* This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id.* at 4, Table 2.

(iii) EPA improperly underestimates the costs by approximately $200 million to justify scrubbers at White Bluff.

EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However, EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices ("CEPCI"). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id.* at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis:

- costs for the reagent handling system;
- costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney;

- the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects;
- the costs associated with replacing the continuous emissions monitoring systems ("CEMS") and associated recalibration and testing costs; and
- costs calculated as percentages of the BOP equipment, material and labor costs.

Id. at 7-8. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id.* at 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[11] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost ("CUECost") model. *Id.* at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[12] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines,

[11] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.

[12] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5 . EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id.* at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMbtu unless fuel sulfur limitations were imposed. Based on historical data and potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction ("AFUDC") from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[13] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30-46 months of construction that would be needed to install

[13] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.

major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[14] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit. Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART.

EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

[14] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of **$7,689-$8,599**/ton at Unit 1 and of **$7,642-$8,546**/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id.* at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately **$3.1 billion** per deciview at Caney Creek and **$2.7 billion** per deciview at Upper Buffalo and, for Unit 2, approximately **$2.9 billion** per decivew at Caney Creek and **$2.6 billion** per deciview at Upper Buffalo.[15]

[15] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2.iii below. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

4. Emissions reductions at White Bluff will be achieved through interim controls.

In addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the units' permitted SO_2 emission rates. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018.

NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NOx BART for all of Arkansas' EGUs.

However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NOx BART limits in the final FIP, Entergy proposes that the units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[16] *See* 79 Fed. Reg. at 18,974-75. Although the cost effectiveness

[16] As explained further in Section III.E below, this limit is different from the limit that Entergy proposed as NOx BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator ("MISO") and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NOx control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary

of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

This combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes.

1. EPA's reasonable progress analysis does not follow prior actions.

For reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. *See* Section III.C below. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NOx limitations on the two coal-fired units at Independence. By focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) ("Reasonable Progress Guidance").[17] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

---

to ensure that the White Bluff units can comply with the NOx limit at the lower loads that have become a more common operating condition for the units.

[17] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf.

(i) EPA failed to determine visibility impact and the scope of Arkansas sources' contribution to visibility impairment.

EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NOx within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[18]

EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[19] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[20] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[21] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.* at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF,

---

[18] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[19] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").

[20] *Id.* at A-15 – A-26.

[21] *Id.* at A-49.

single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635.

EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress.*[22] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

(ii) EPA's review and determination of cost effectiveness is inconsistent with other state programs.

EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states. *See* Section III.C.3 below.

(iii) EPA's evaluation and application of NOx control requirements is inconsistent with other state programs.

EPA's decision to evaluate *and propose* NOx controls at Independence stands completely opposite its decision not to even evaluate NOx controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NOx limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NOx, and almost not

[22] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

at all by Independence. *See* Section III.C.2 below. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP. *See* Section III.C.1 below.

2. EPA is obliged to act consistently in promulgating rules.

Reviewed individually, the issues identified above evidence an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time.

Units 1 and 2 at the Independence Station are not subject to BART. 80 Fed. Reg. at 18,991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective." EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here.

Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NOx controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and

operation of dry FGD systems, and a rolling 30-day average NOx emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id.* at 18,994, 18,997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id.* at 18,994.

EPA's justification for imposing SO_2 and NOx emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions." *Id.* at 18,992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. *Id.* at 18,994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NOx emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPS. *See* Section III.B above. Further, emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period.

EPA also improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[23] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources,[24] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost EAI's customers and co-owners over $1 billion.

1. Controls on Independence do not further the goal of the Regional Haze Program.

The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce

[23] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[24] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id.*

emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

64 Fed. Reg. 35,714, 35,752 (July 1, 1999). EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4; *see also id.* at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Thus, the threshold question is whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added). Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly no. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational").

(i) Arkansas' Class I areas are, and will remain, below the glide path well beyond the first planning period.

The proposed emission limits for Independence are not necessary to achieve reasonable progress because ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[25] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current five-year average shows that, as of 2011, Caney Creek has achieved 73%

[25] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the five-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id.* at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id.* at 42-43. EPA acknowledges these facts in the Proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 Fed. Reg. at 18,992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[26]

Entergy has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[27] Recent IMPROVE monitoring data show that the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[28] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo.[29] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

---

[26] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 Fed. Reg. 11,958, 11,966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 Fed. Reg. 38,007 (June 26, 2012).

[27] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment Report*, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[28] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

[29] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

Figure 1

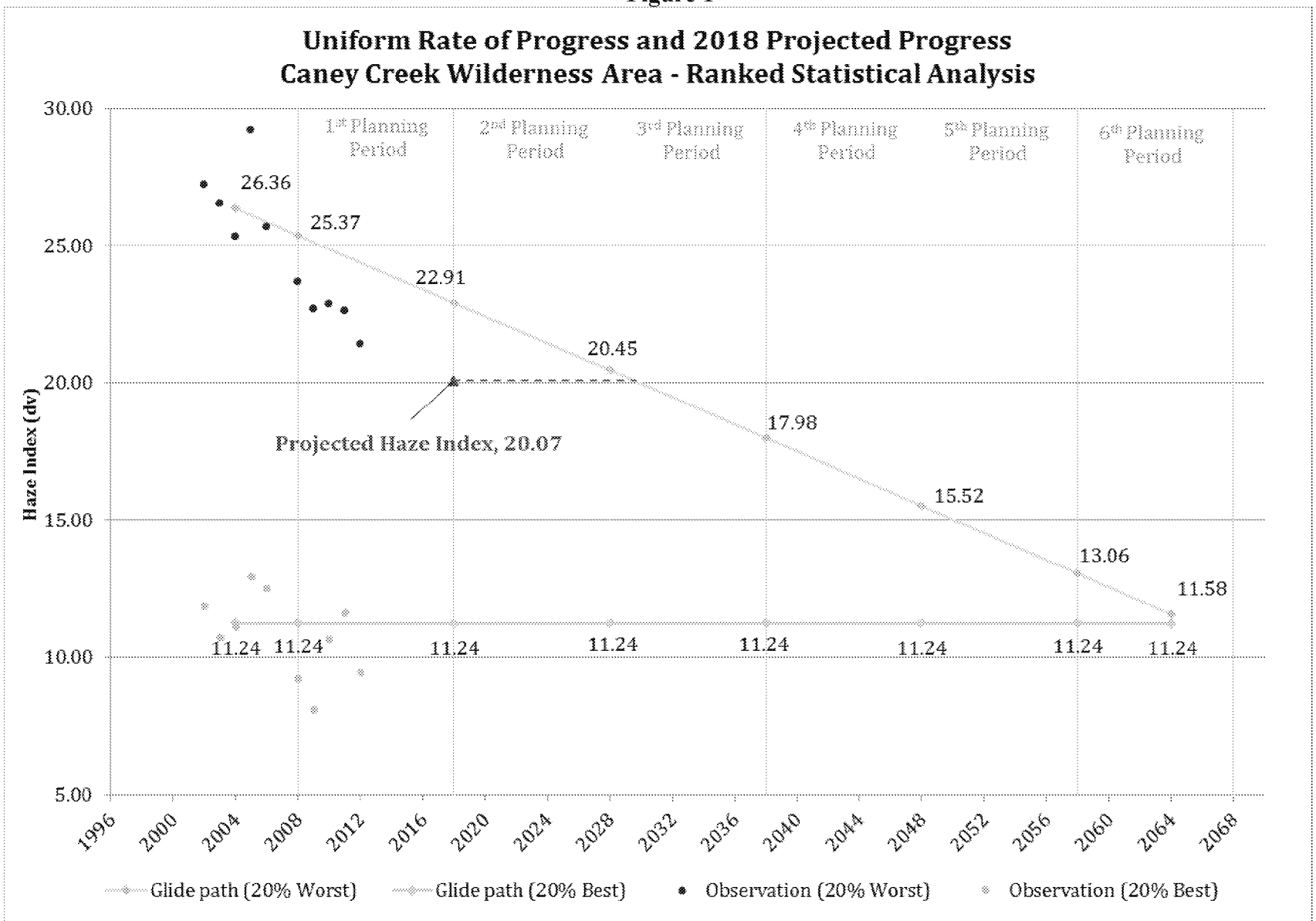
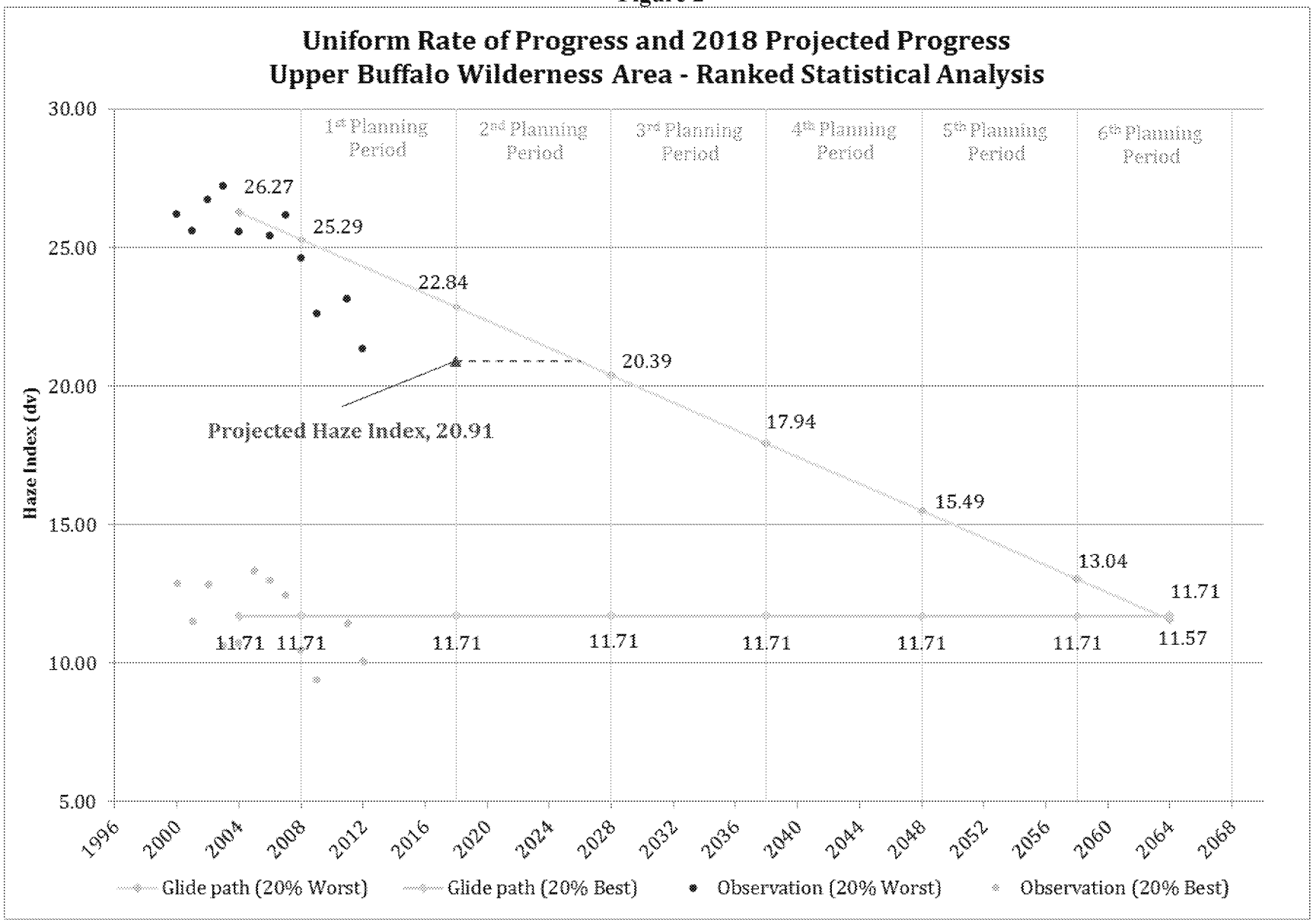

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 2


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
11.71
11.71
11.71
11.71
11.71
11.71
11.71
Projected Haze Index, 20.91
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NOx emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[30] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[31] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NOx reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

(ii) Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas.

In the Proposal, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[32]

---

[30] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.

[31] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions. *See* footnote 5 above.

[32] Figures 3 and 4, as well as Figures 5 and 6, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

Figure 3

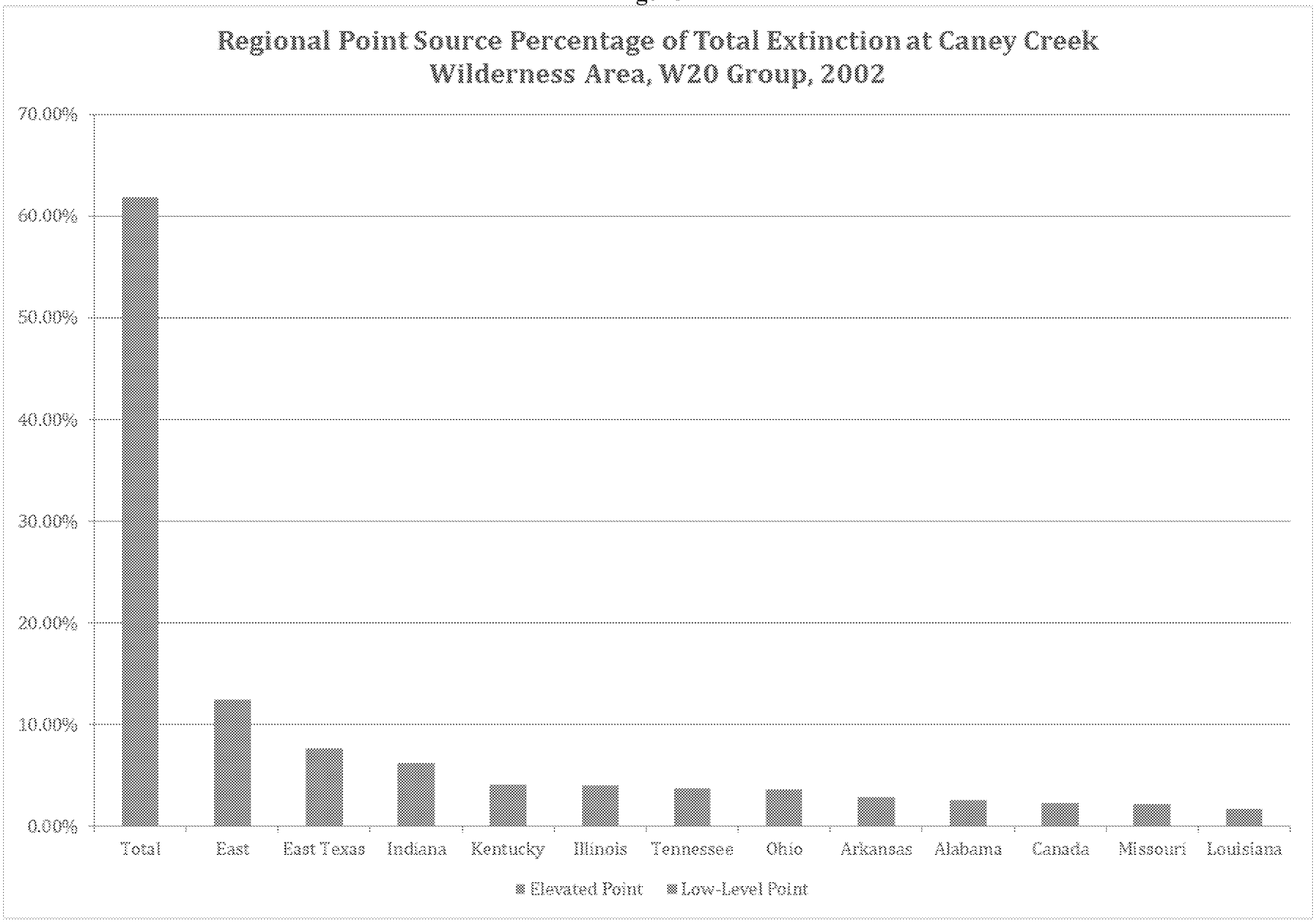
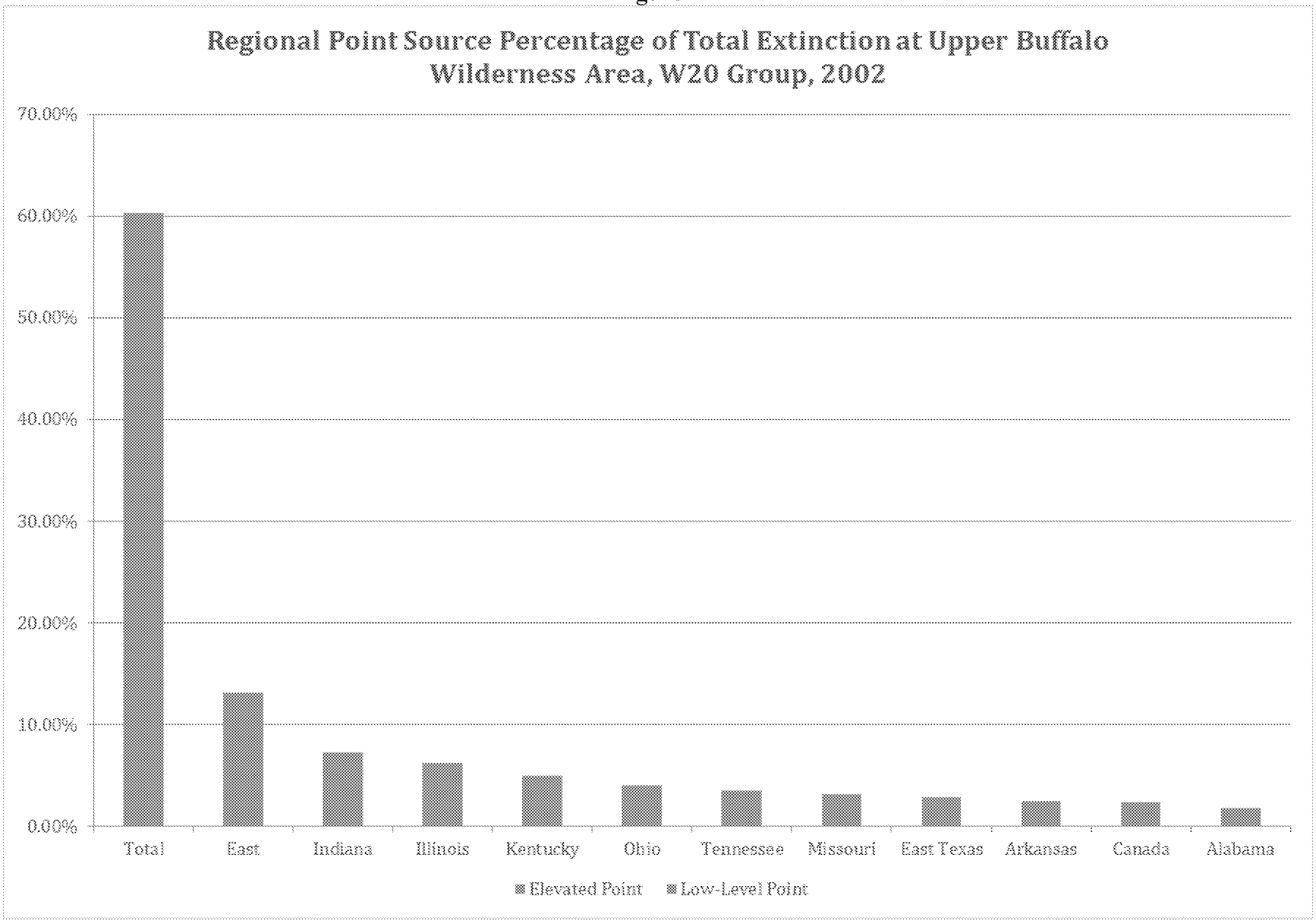

Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

Figure 4


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

Figures 3 and 4 display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only **2.87%**, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a **2.47%** contribution.

In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

Figure 5

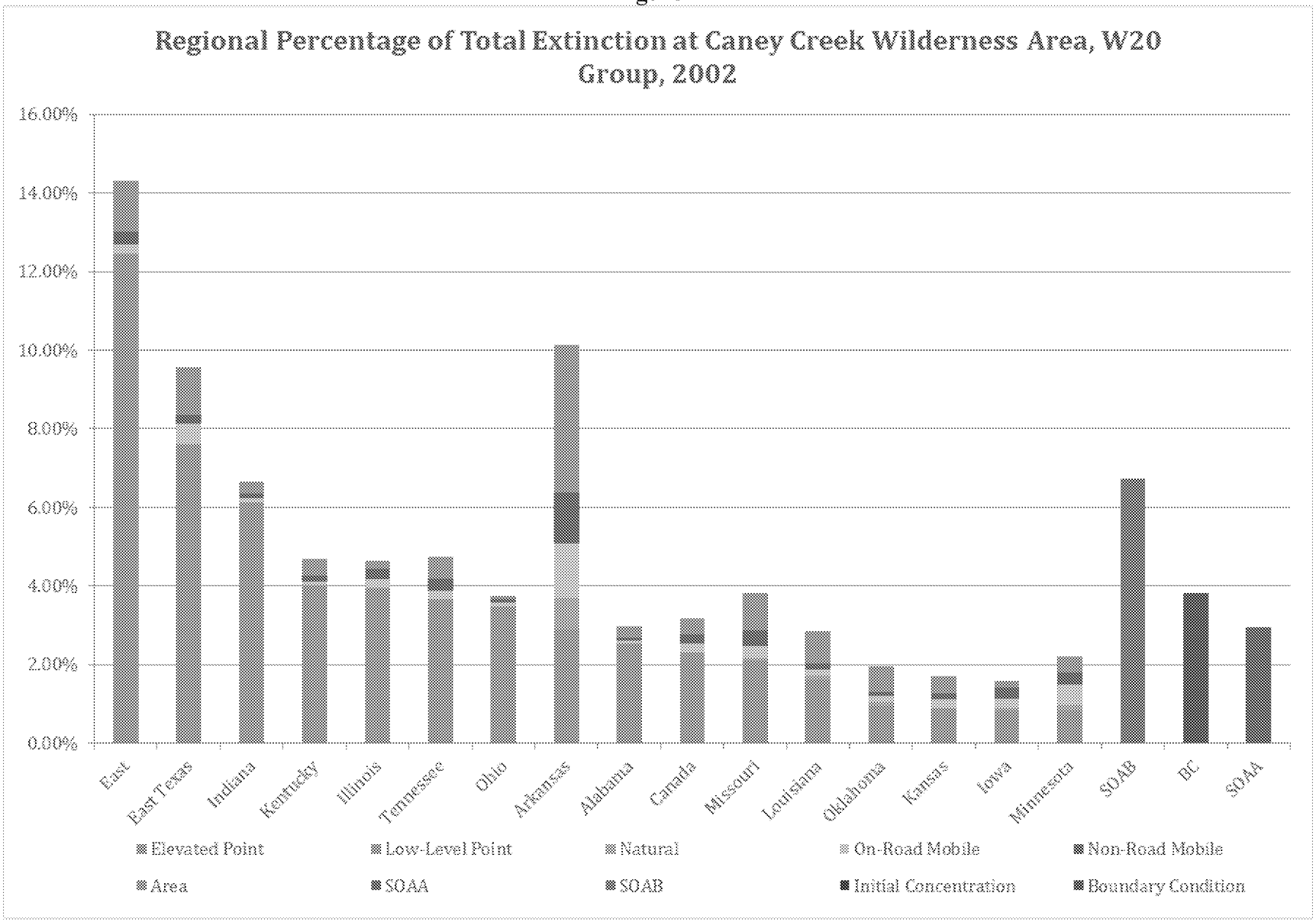
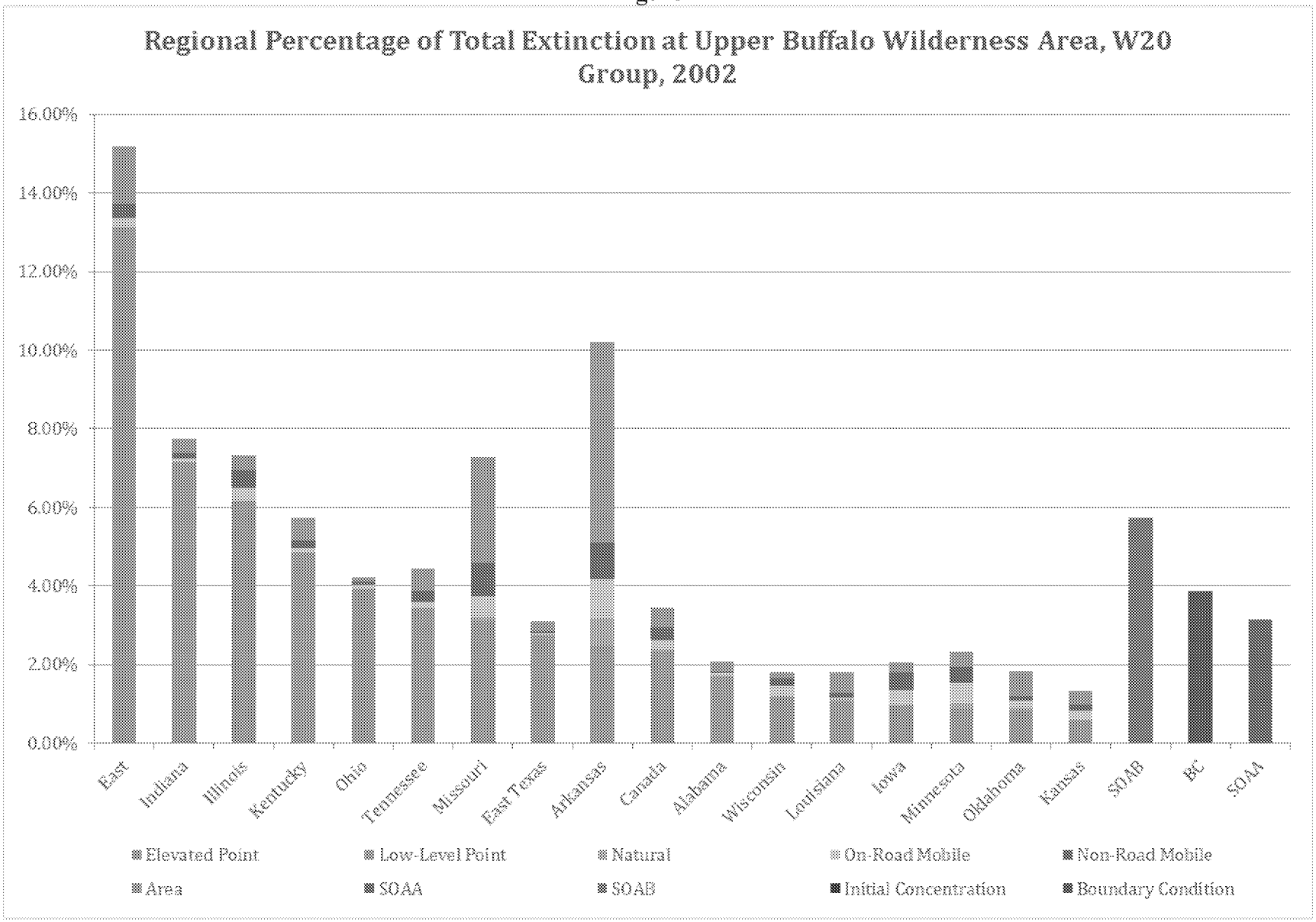

Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Oklahoma
Kansas
Iowa
Minnesota
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

Figure 6


Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Wisconsin
Louisiana
Iowa
Minnesota
Oklahoma
Kansas
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

At Caney Creek, Arkansas area sources contribute **3.75%** of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only **2.87%**. Even more significantly, Arkansas area sources contributed **5.09%** towards extinction at Upper Buffalo compared to **2.47%** from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

(iii) Emissions from out-of-state sources will continue to improve.

Entergy's analysis demonstrates that Arkansas' Class I areas will remain below the glide path in the first planning period and well into the second based on actual data (*see* Section III.C.1.i above); however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[33] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO_2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO_2 and NOx emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 (demonstrating declining emissions trends and the contributions of EGUs).

[33] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

Figure 7

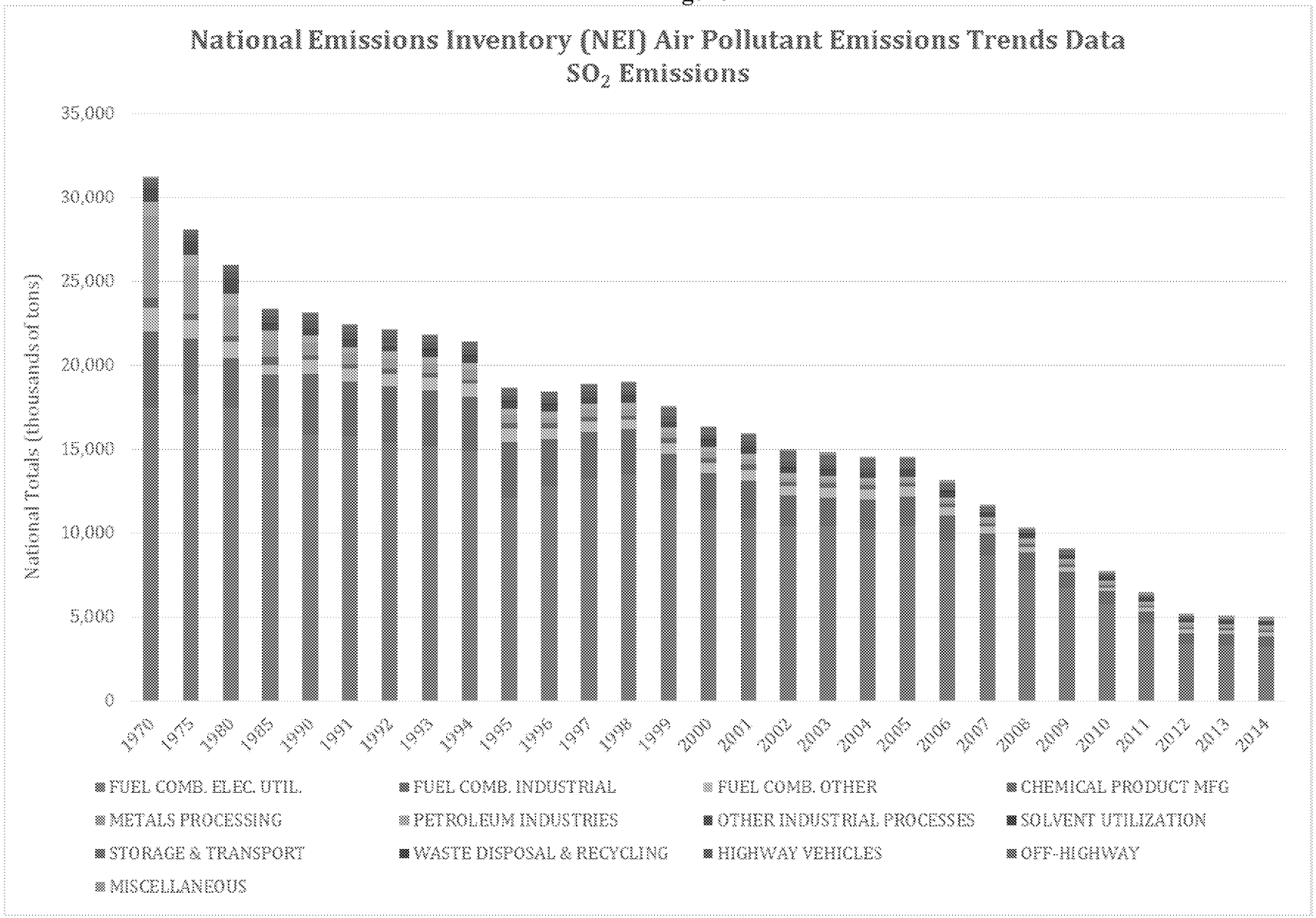
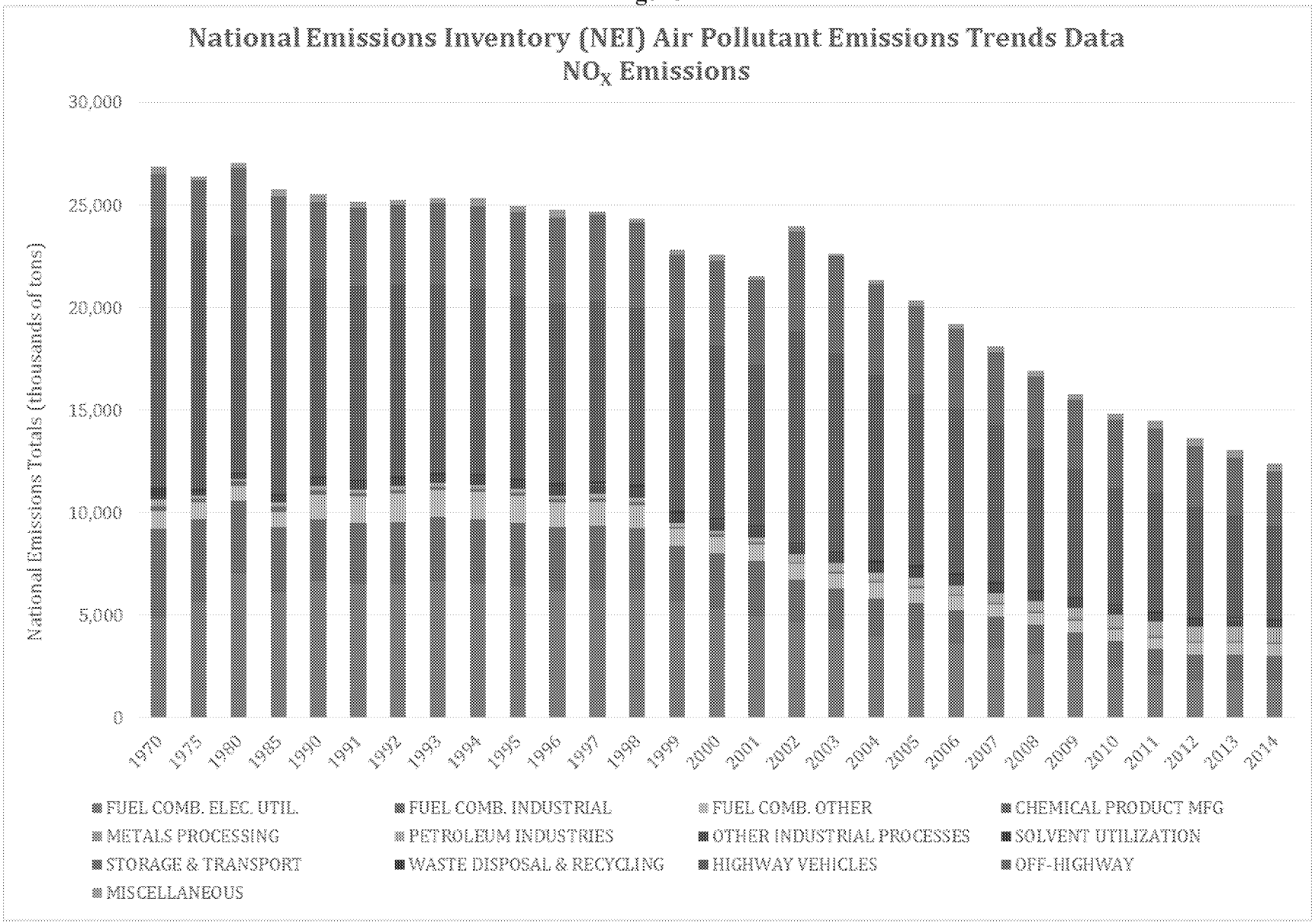

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

Figure 8


National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
NO_X Emissions
National Emissions Totals (thousands of tons)
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

According to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

Reasonable Progress Guidance at 4-1. EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress.

EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id.* The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id.* The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures 9 and 10.[34] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NOx controls at Independence are warranted.

[34] Figures 9 and 10 assume no FIP controls on any of the Arkansas sources. Also, the total haze index values presented in Figures 9 and 10 are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days. *See* Section III.C.1.i, above.

Figure 9

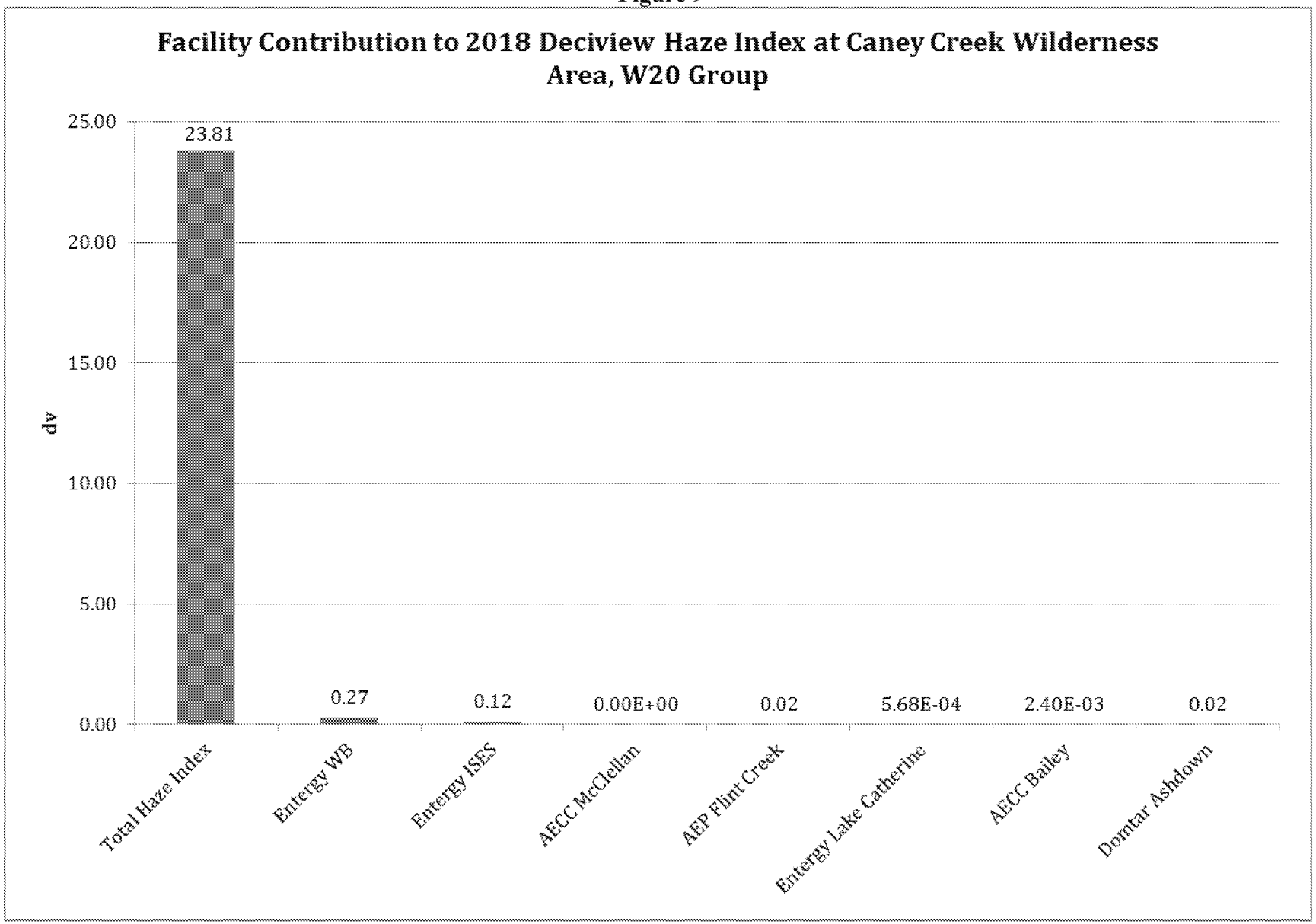
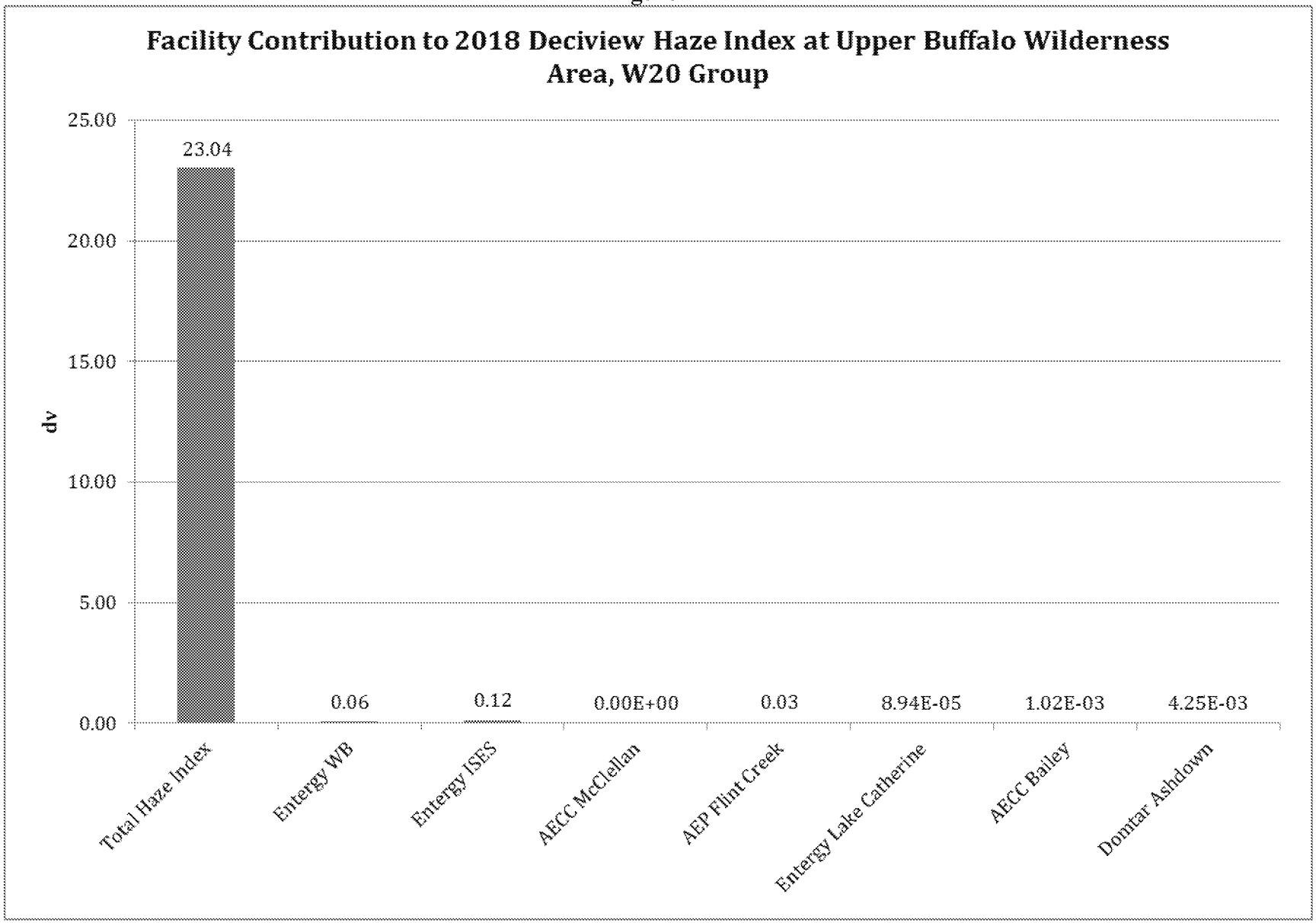

Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10


Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.04
0.06
0.12
0.00E+00
0.03
8.94E-05
1.02E-03
4.25E-03
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

(i) CALPUFF modeling cannot be used to justify reasonable progress controls at Independence.

Entergy acknowledges that, under the Regional Haze Rule, "the URP does not establish a 'safe harbor' for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id.* EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id.* at 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id.* at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the

application of a chemical transport grid model." Draft Modeling Guidance at 22.[35] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id.* at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone.

80 Fed. Reg. at 45,349. CALPUFF is clearly inferior in this regard.

Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[36] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with

[35] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf.
[36] Docket ID EPA-HQ-OAR-2015-0310-0004.

realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal.... Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

(ii) The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.83 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id.* at 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NOx limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

Another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[37] *See* Figure 11 below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 above), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP

[37] Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.

would not reach that haze level until approximately 2048.[38] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

[38] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See* Figure 12.

Figure 11

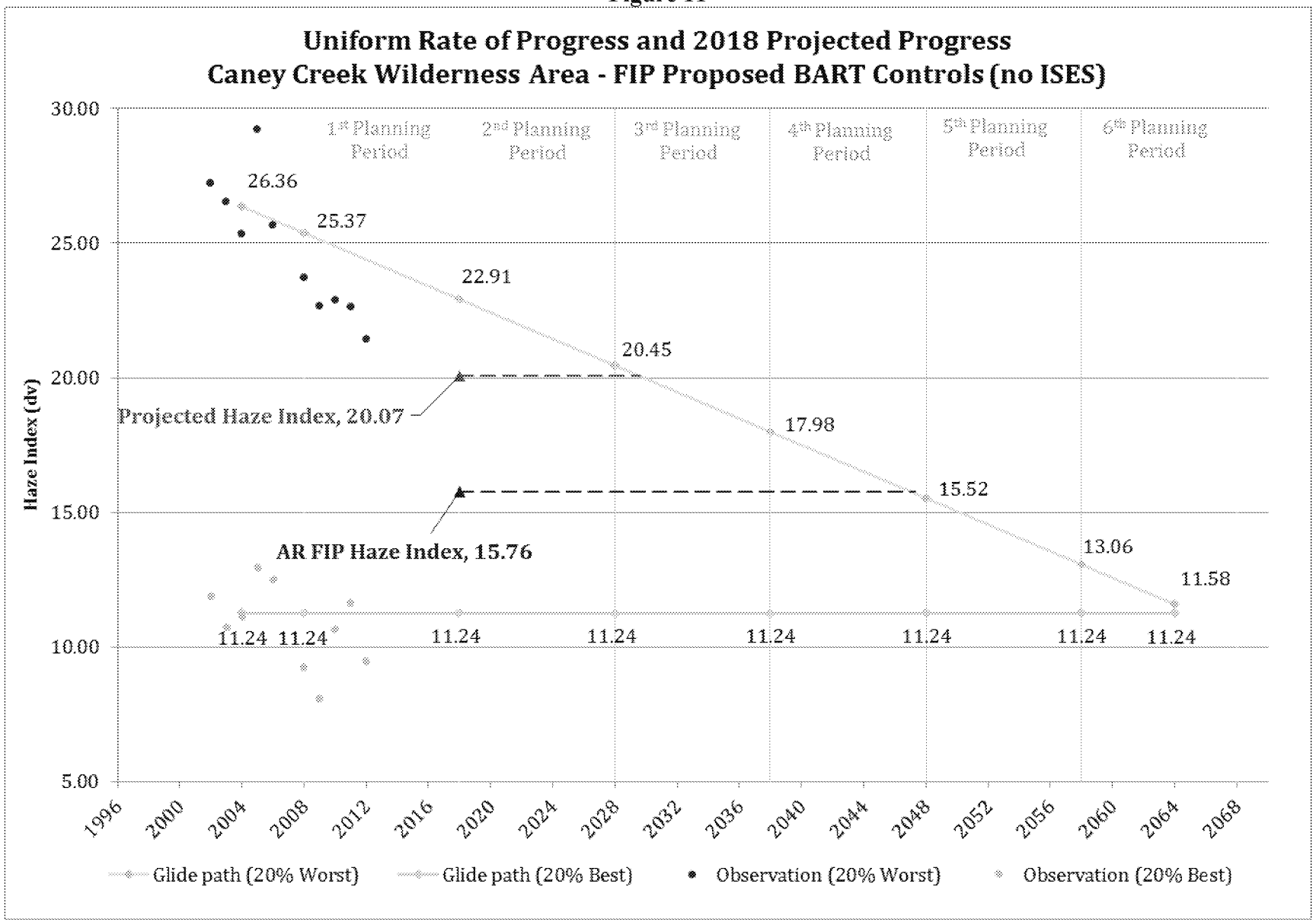
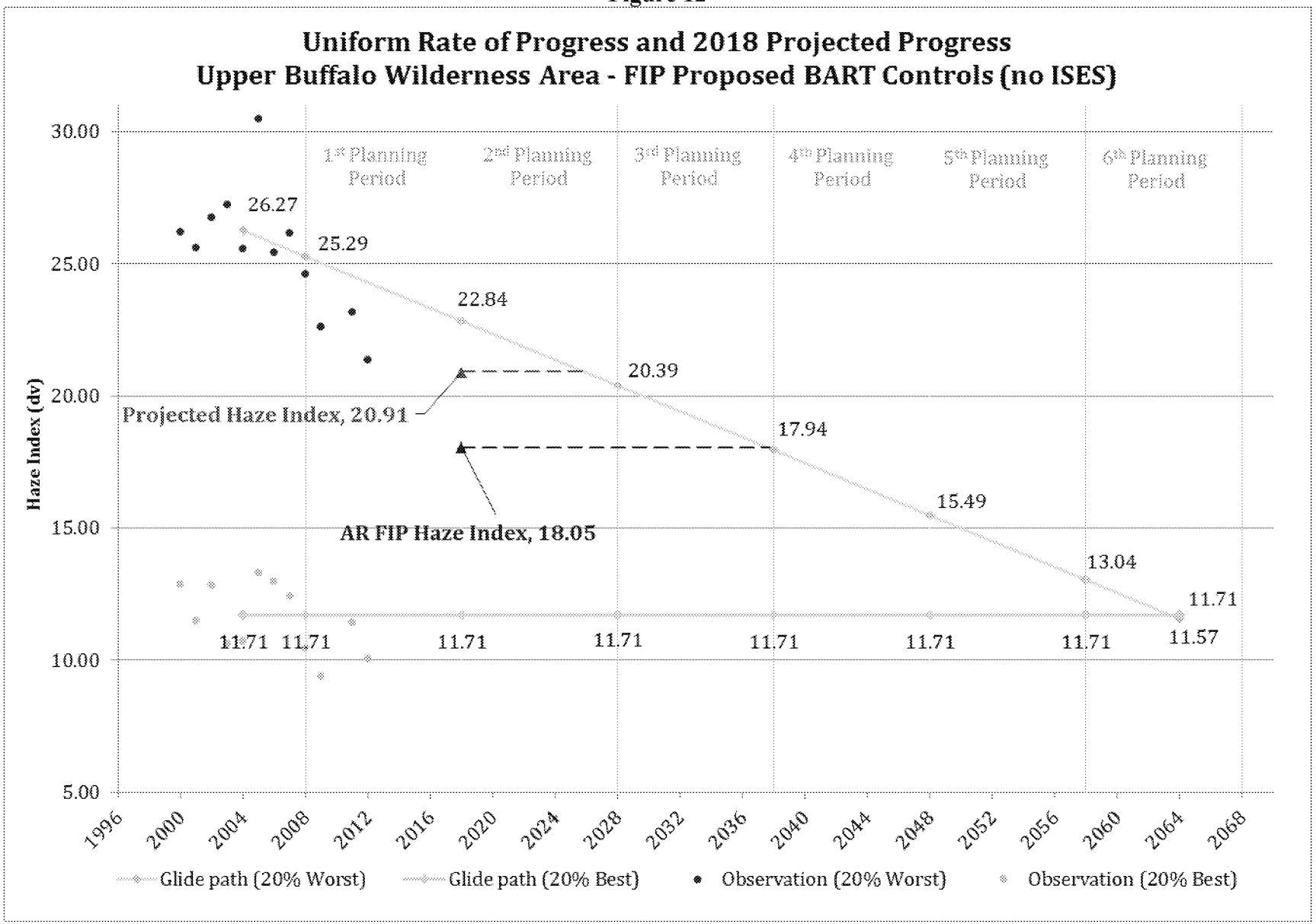

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
AR FIP Haze Index, 15.76
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 12


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
11.71
11.71
11.71
11.71
11.71
11.71
Projected Haze Index, 20.91
AR FIP Haze Index, 18.05
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

(iii) Controls on Independence will not yield perceptible visibility benefits.

As demonstrated above, EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id.* at 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately **0.08** dv at Caney Creek and **0.07** dv at Upper Buffalo).[39] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19 dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[40] Requiring imperceptible visibility improvements is simply unreasonable. The

[39] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.
[40] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id.* at 1242, Figure 2.

CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

In addition, the demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[41] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NOx molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NOx emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NOx molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NOx will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

(iv) EPA has offered no justification for requiring controls to achieve reasonable progress for this planning period when the controls cannot even be installed until the next planning period.

EPA further exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[42] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[43]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods

[41] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

[42] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[43] The Proposed FIP provides for NOx emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

3. The proposed controls are not cost effective.

EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost effective to do so. 80 Fed. Reg. at 18,994-97. First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, Entergy disagrees with EPA's estimated costs for the installation of dry scrubbers at White Bluff. *See* Section III.A.2 above. Assuming that dry FGD controls at Independence would cost the same as at White Bluff, the controls at Independence also would cost over $1 billion. *See* Section III.A.3 above. This is not cost effective on a $/ton basis for reasonable progress purposes as it would result in $4,234 per ton of SO_2 removed at Independence Unit 1 and $3,909 per ton of SO_2 removed at Independence Unit 2.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

(i) Requiring over $1 billion in controls at Independence to achieve an unnecessary and imperceptible change in visibility at Arkansas' Class I areas is patently unreasonable.

Despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton

removed for Unit 1 and \$2,286/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of \$2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Additionally, EPA failed to consider the cost effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately **\$1.33 billion** per dv improvement at Caney Creek and **\$1.53 billion** per dv improvement at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

(ii) EPA inappropriately revised Entergy's control cost analysis by eliminating consideration of proper costs.

EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed above in Section III.A.2, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B.

As discussed in Section III.A.3 above, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over \$1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost effectiveness at Independence Unit 1 of \$4,234 and of \$3,909 at Independence Unit 2, which, as noted above, is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that would result from installing these controls is estimated at approximately \$1.33 billion at Caney Creek and \$1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence.

EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress.

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.[44]

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less.

Entergy is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy also is proposing to meet lower SO_2 emission rates at all four units by 2018, and proposes to install LNB/SOFA at all four units and meet a 30-day rolling average NOx emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP.[45] This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal. *See* Figures 13 and 14 below, which compare the projected 2018 haze index at each Arkansas Class I area based on the Ranked Statistical Analysis, to the

[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, under Entergy's four-unit approach, the NOx control measures and lower SO_2 emission rate proposed for White Bluff would constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence are more than sufficient for reasonable progress purposes for this planning period.

[45] Entergy's rationale for the proposed NOx rate is discussed in Section III.E. below.

deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of the Proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Figure 13

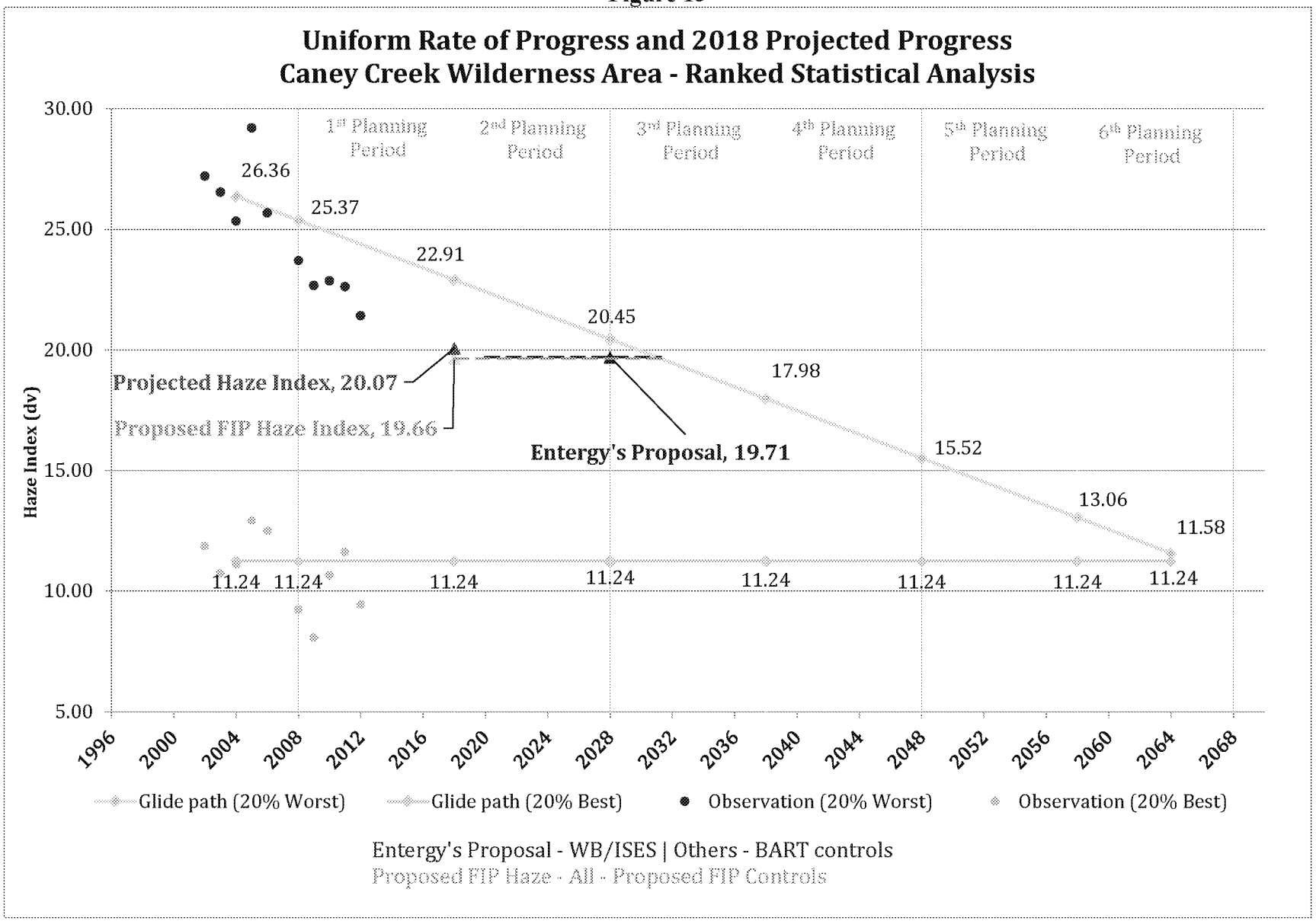
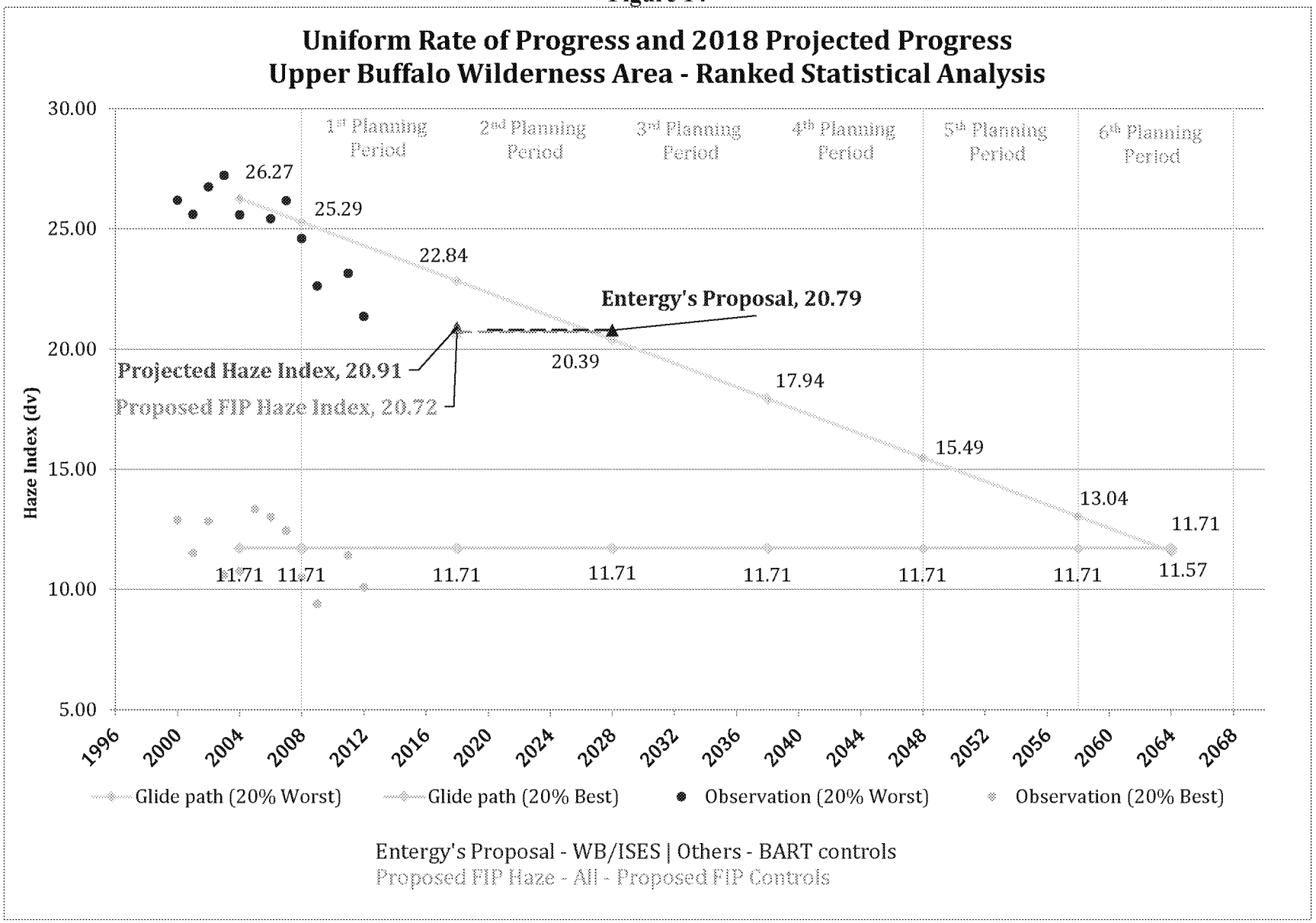

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Figure 14


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
11.71
11.71
11.71
11.71
11.71
11.71
Entergy's Proposal, 20.79
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Entergy's proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 above. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NOx, SO_2, and PM heading into the third planning period.

Ultimately, Entergy's approach would achieve more than 170,000 tons of NOx reductions from White Bluff than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NOx would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NOx and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_2e. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's Proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal.

Entergy opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. For all of the reasons discussed above in Section III.C, controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions.

The NOx emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[46] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are

[46] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

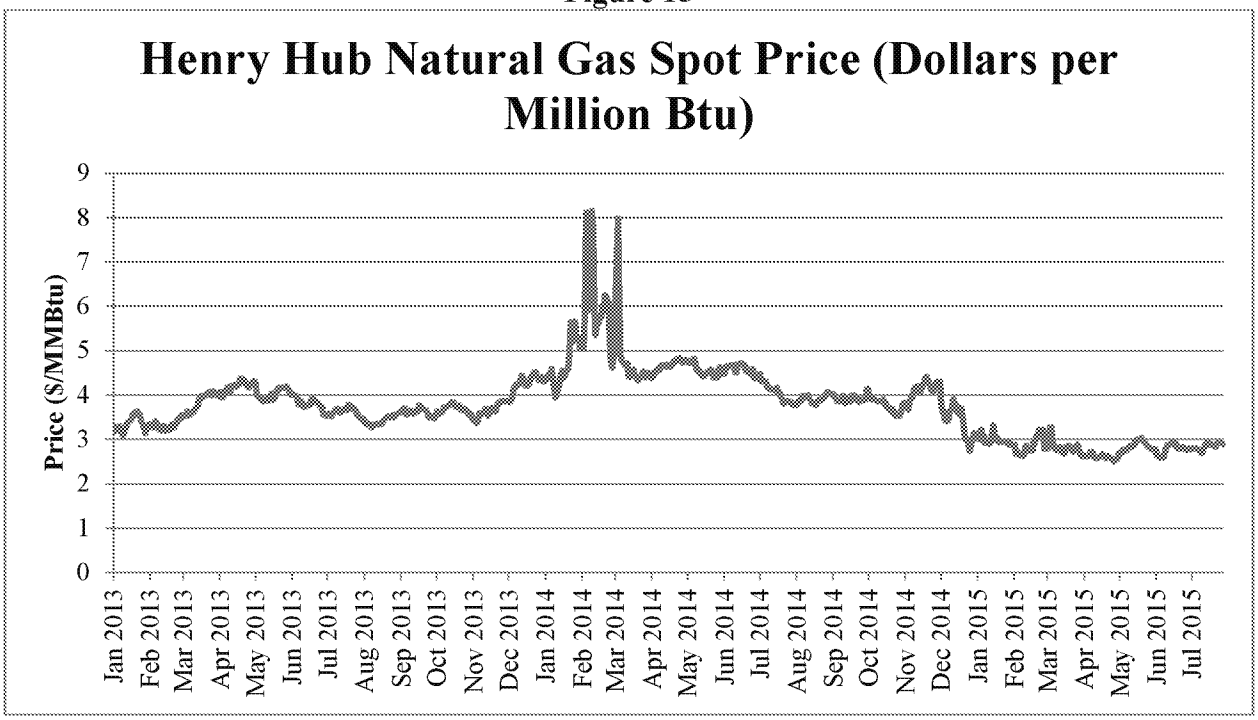
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 (YTD)*	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

This change in dispatch coincided with a sharp drop in natural gas prices which can be seen in Figure 15 below. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Figure 15



This change in dispatch for the units at both White Bluff and Independence is significant with regard to NOx emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[47] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NOx emission rates. This memorandum is attached as Exhibit G to these comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

The concern arises from low-load operation during which periods of higher NOx emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NOx emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NOx emission limit for each unit at both White Bluff and Independence as follows.

> For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average.
>
> And;

[47] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NOx emissions from the units. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

For unit operation at 50-100% of capacity, a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NOx emission reductions.

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls.

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated.

EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NOx BART controls on Lake Catherine Unit 4.

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4.

If EPA finalizes a determination that Lake Catherine Unit 4 should be subject to NOx BART controls, EPA should not impose source-specific NOx controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NOx BART in Arkansas for all EGUs, as discussed in Section III.A.4 above. Compliance with CSAPR will ensure that NOx emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NOx BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NOx BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id.* at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as

BART based on either average cost effectiveness or incremental cost effectiveness. *Id.* Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014.[48] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* at 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas.

EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, and Independence, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18,972 (Tables 34 and 35); 18,974 (Tables 37 and 38); 18,978 (Table 42); 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas.

The preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the

[48] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[49] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

On a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. As discussed in Section III.C.2 above, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211.

EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit

[49] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

I. Additional Comments.

- Entergy agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NOx, and PM. 80 Fed. Reg. at 18,975.

- Entergy agrees that 2009-2011 should be used as the baseline period for NOx for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

- If EPA finalizes a source-specific NOx BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NOx CEMS with a continuous NOx analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NOx analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NOx correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

- Entergy agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993.

- Entergy agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

- Entergy disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and are hereby incorporated by reference.

IV. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed FIP. Entergy strongly urges EPA to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, as Entergy as proposed, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure superior, long-term visibility benefits than would the Proposed FIP. It also would deliver important non-haze environmental benefits, including a dramatic decrease in GHG emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NOx emissions. Entergy respectfully requests that EPA amend the Proposed FIP as described in these comments.

Respectfully submitted,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

SL-012913
Final
July 14, 2015
Project No: 13027-002

PREPARED BY

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

EPA-HQ-2018-002296

TABLE OF CONTENTS

EXECUTIVE SUMMARY ES-1

1. INTRODUCTION 1

2. COMMENTS TO THE FIP TSD – SO_2 EMISSION REDUCTION ERRORS 2

2.1 BASELINE EMISSION RATES 2
2.2 SO_2 EMISSION REDUCTION 3
2.3 SO_2 EMISSION RATE 4

3. COMMENTS TO THE COST TSD – ANNUALIZED COST ERRORS 6

3.1 COST TSD, SECTION 2 – SDA COST ANALYSIS METHODOLOGY 6
3.2 COST TSD SECTION 2.3 – USE OF THE 2009 ALSTOM COST ANALYSIS 7
3.3 COST TSD SECTION 2.4 – USE OF THE S&L BALANCE OF PLANT COSTS 7
3.4 COST TSD SECTION 2.5 – UNDOCUMENTED OR DISALLOWED COST ITEMS 10
3.5 COST TSD SECTION 2.6 – ESCALATION 11
3.6 COST TSD SECTION 2.7 – OPERATING AND MAINTENANCE (O&M) COSTS 13
3.7 COST TSD SECTION 3.1 – ENTERGY'S COAL SULFUR ASSUMPTION 14
3.8 COST TSD SECTION 4.1 – EPA'S CONSERVATISM IN COST ESTIMATING 17
3.9 REMAINING USEFUL LIFE 17

4. COST TSD SECTION 5 – INCLUSION OF INDEPENDENCE UNDER REASONABLE PROGRESS GOALS (RPGS) 19

5. CONCLUSION 22

ATTACHMENTS

Attachment A – Cost-Effectiveness Calculation

Exhibit A to EAI Comments

ED_002110_00032342-00063

EXECUTIVE SUMMARY

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[1] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

Cost-effectiveness is influenced by two variables: the total annualized cost to retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable.

Based on our review, the following items in EPA's analysis were identified to result in overstating the tons of SO_2 removed:

- After defining a baseline SO_2 emission period of between 2009 and 2013, EPA arbitrarily excluded the years with the maximum and minimum annual averages;
- When calculating SO_2 emission reductions due to FGD retrofits, EPA incorrectly used maximum monthly averages for baseline SO_2 emissions; and
- A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities.

In addition, the following items in EPA's analysis were identified to result in understating the annualized cost of the dry FGD retrofit:

- EPA subtracted over $23 million in BOP costs for both units because they mistakenly believed the equipment to be included in Alstom's scope;
- Because EPA mistakenly removed BOP cost items that should be included in the estimate, they over-estimated and misapplied percent reductions to other cost items, resulting in cost subtractions of over $7 million for both units;

[1] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

- EPA removed over $41 million per unit in Owner's Costs despite the fact that these are real costs that the Entergy will incur;
- EPA under-estimated cost escalation, and in some cases de-escalated costs, by relying on cost indices rather than using vendor pricing information, all of which resulted in under-estimating costs by more than $42 million per unit;
- EPA incorrectly utilized the IPM model, which is not designed to evaluated site-specific costs, to verify O&M costs at White Bluff;
- EPA scaled capital costs to a design fuel of 0.68 lb/MMBtu, which when compared to operating data, is completely insufficient to ensure compliance with the proposed emission limits for nearly half of the time;
- While we agree that O&M costs should be based on 0.68 lb/MMBtu, EPA's methodology to scale direct O&M costs based on fuel sulfur levels is incorrect and resulted in under-estimating these costs by over $5 million per unit;
- EPA incorrectly scaled indirect O&M costs using fuel sulfur levels, despite these costs being estimated as percentages of capital cost, which resulted in under-estimating these costs by over $4 million; and
- EPA used a remaining useful life of 30 years, when Entergy is proposing to cease coal-fired operations on these units in 2027 and 2028, resulting in a remaining useful life of 6 or 7 years.

As discussed above, S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits. To better address EPA's questions on scope and cost items which it did not understand, S&L has prepared an updated cost report to clarify and provide further detail around scope items and cost items included in the estimate.[2] The corrected and updated cost-effectiveness for both White Bluff units is greater than $7500/ton, which is clearly not cost effective.

With respect to EPA's Reasonable Progress Goal (RPG) analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

[2] *See* S&L Report #012831 ("White Bluff Dry FGD Cost Estimate and Technical Basis") (July 2015).

1. INTRODUCTION

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[3] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

S&L's experience in the electric power industry, as well as our experience with the Entergy facilities makes us uniquely qualified to perform this review. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with various FGD technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, and 25 dry sorbent injection (DSI) projects, all of which are technologies that are used to control SO_2 emissions. Our first-hand experience with these technologies provides us with a thorough understanding of both capital and operating and maintenance (O&M) costs associated with these technologies, as well as providing us with a comprehensive understanding of the achievable emission rates and limitations of these technologies.

S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. Cost-effectiveness is influenced by two variables: the total annualized cost of retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits.

[3] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

2. Comments to the FIP TSD – SO_2 Emission Reduction Errors

The majority of S&L's comments are relative to EPA's Cost TSD; however, we note that in its FIP TSD, EPA incorrectly estimates both baseline emissions and SO_2 emission reductions that would result from the retrofit of dry FGD systems at White Bluff station. In addition, in proposing emission rates for White Bluff station, EPA proposed SO_2 emission limits that are consistent with performance guarantees offered by dry FGD suppliers during initial performance testing, not emission rates that are achievable over the 30-year life EPA assumed in its analysis. The following sections describe EPA's flawed analysis contained in the FIP TSD.

2.1 Baseline Emission Rates

Although baseline emission rates identified in Entergy's original BART analysis[4] were calculated based on the average annual emission rates from 2001 to 2003, in the FIP TSD, EPA redefines baseline emission by using a 3-year average of annual average SO_2 emissions from the years 2009 to 2013, excluding the years with the maximum and minimum annual averages.[5]

We can find no reason to reject EPA's selection of 2009 to 2013 as the baseline period as it represents more recent operation. However, the approach used by EPA to exclude the maximum and minimum values is entirely arbitrary and EPA does not explain how this approach represents a more realistic depiction of anticipated emissions from the existing sources.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source."[6] In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period.[7] However, EPA provides no explanation or analysis to demonstrate that the approach taken results in a realistic depiction of anticipated annual emissions from White Bluff and Independence. In addition, there is no basis for concluding that EPA's approach of excluding actual emissions data more accurately represents the actual operation of the units. Finally, to our knowledge, with the exception of EPA's proposed Texas FIP, this approach has not been used previously by EPA as a methodology for evaluating baseline emissions in other evaluations (and even if EPA had done so, it is not justified here).

The following table shows a comparison between the baseline emissions as established using EPA's approach and baseline emissions calculated as a straight average for various timeframes within the 2009-2013 period.

[4] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas, October 2013, Trinity Consultants.
[5] *See* EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, under Annual Emissions.
[6] 40 CFR Part 51 Appendix Y.
[7] *Id.*

Table 1: Comparison of Baseline SO_2 Emissions for White Bluff and Independence

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

*EPA's approach includes 2009-2013 3-year average, excluding maximum and minimum years.

With the exception of White Bluff 1, EPA's approach of eliminating the maximum and minimum values results in higher baseline SO_2 emissions compared to averaging the entire 5-year period. In all cases, there is at least one other approach that would result in lower baseline SO_2 emissions compared to EPA's approach. By overestimating the baseline SO_2 emissions, EPA overstates the amount of SO_2 that would be removed and, thus, overstates the cost-effectiveness of the FGD retrofit projects.

2.2 SO_2 Emission Reduction

SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages, which are significantly higher than the annual averages actually used to calculate baseline emissions.

The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA.

Table 2: SO_2 Emission Reductions for White Bluff and Independence

Unit	EPA Approach Using Maximum Monthly SO_2 emission and 3-Year Baseline (tons)	Using 5-Year Average Heat Input and Baseline (tons)
White Bluff 1	14,363	14,264
White Bluff 2	15,221	14,353
Independence 1	12,912	12,607
Independence 2	13,990	13,655

Table 2 compares EPA's incorrect methodology to estimate SO_2 emission reductions at the Entergy Units to the more accurate methodology described above of using the 5-year average heat input from the baseline period. EPA's methodology overestimated the SO_2 emission reduction in all cases and therefore overstates the cost-effectiveness of the FGD retrofits at each unit.

2.3 SO_2 Emission Rate

EPA proposed SO_2 emission rates based on the assumption that a retrofit dry FGD will achieve a controlled SO_2 emission rate of 0.06 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. In several places, EPA cites the IPM dry FGD cost development document, which states: the "[r]ecommended SO_2 emission floor = 0.08 lb/MMBtu."[8]

EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

Dry FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler.

[8] Sargent & Lundy LLC, *IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology*, March 2013.

Furthermore, as shown in Table 3, S&L investigated permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu, and that includes the more efficient CDS dry FGD systems. The last unit shown in the table includes the lowest permit limit of any of the dry FGD systems listed, but this value still contains the necessary margin because the averaging period is much longer (i.e. 12 months), and because the dry FGD system was installed as part of a new boiler project, so it was incorporated into the new unit design which inherently minimizes some of the design challenges associated with retrofitting, where non-ideal layouts can lead to non-ideal flow distribution inside the absorbers.

Projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.06 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. As indicated in Table, using a limit of 0.08 lb/MMBtu to provide the recommended margin would still be an aggressive permit limit compared to other dry FGD projects.

Table 3: SO_2 Permit Limits for Dry FGD Projects

Reference Plant	Permit SO_2 Limit	Permit Averaging Period
Plant 1 (SDA)	0.09 lb/MMBtu	30 day rolling
Plant 2 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 3 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 4 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 5 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 6 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 7 (CDS)	0.09 lb/MMBtu	30 day rolling
Plant 8 (CDS)	0.10 lb/MMBtu	30 day rolling
Plant 9 (CDS)*	0.07 lb/MMBtu	12-month rolling average

*This unit was a new unit, not a retrofit

EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

3. Comments to the Cost TSD – Annualized Cost Errors

S&L's remaining comments are focused on EPA's Cost TSD. Our comments follow the same organization of EPA's Cost TSD document and are contained in the following sections.

3.1 Cost TSD, Section 2 – SDA Cost Analysis Methodology

EPA states that the "Control Cost Manual uses the overnight method of cost estimating, widely used in the utility industry.[9]" To support this conclusion, EPA references its own characterization of the CCM methodology published in the preamble to the Oklahoma Regional Haze FIP.[10] Using the overnight methodology, EPA removed certain costs from the SDA cost estimate, including Owner's costs and interest incurred during the construction period. We disagree that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs."[11] However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational."[12] Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove[13] from the SDA capital cost estimate

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner."[14] However, excluding financing costs will bias the cost-effectiveness comparison toward the high-capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

---

[9] Cost TSD, page 1.
[10] *Id.*
[11] *Id.*
[12] EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010, pg. 2.
[13] *See* August 21, 2013 email from Dayana Medina of EPA Region 6 to Mary Pettyjohn of the Arkansas DEQ.
[14] *Cost TSD, page 1.*

3.2 Cost TSD Section 2.3 – Use of the 2009 Alstom Cost Analysis

EPA invited Entergy to clarify certain issues associated with Alstom's 2010 quotation, including a misunderstanding regarding the scope of the dry FGD vendor's contract. In S&L Report #012831 of our comments, we have included a report that explicitly describes the scope of supply for the dry FGD vendor as compared to the balance of plant (BOP) scope of work. EPA made several incorrect assumptions regarding Alstom's scope that led to incorrect adjustments to the BOP cost estimate, as described in Section 3.3 of our comments. Furthermore, EPA's approach to escalating the Alstom quotation was incorrect as described in Section 3.5 of our comments.

3.3 Cost TSD Section 2.4 – Use of the S&L Balance of Plant Costs

EPA mistakenly subtracted BOP costs because they mistakenly believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system were not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NO_X control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope.

EPA mistakenly deleted a total of $255,000 to paint the Chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate.

EPA mistakenly removed a total of $390,000 for costs associating with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these

monitors including conducting a Relative Accuracy Test Audit (RATA) test.

Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Table 4: Excluded BOP Costs (Corrected, Total for Both Units)

	Equipment	Material	Labor	Total
Total BOP Cost	$45,561,000	$35,120,000	$80,863,000	$161,544,000
Eliminate U1 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Eliminate U2 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Total Eliminated Cost	$7,244,000	$3,200,000	$6,146,000	$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In Table 4, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5.

EPA excluded a total of $51,733,667 from the estimate, but Tables 4 and 5 show that only $20,724,543 was justified because NO_X control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed $31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Table 5: Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions*			
DESCRIPTION	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @ 5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								**$20,724,543**

*Same methodology used as EPA but percentages applied are from Table 4

3.4 Cost TSD Section 2.5 – Undocumented or Disallowed Cost Items

Owner's Costs include a variety of costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant
- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[15] CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.

To address the items in this section, we included a section in S&L Report #012831 that describes Entergy's Owner's costs and how they were developed. We believe EPA deleted these Owner's costs because EPA did not understand how they were defined and therefore, incorrectly assumed that they did not reflect real costs to Entergy. In total, EPA removed $41,741,743 per unit from the original estimate which should be included. Removing these costs resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff and Independence. Detailed explanations of these costs are included in S&L Report #012831 to help EPA understand

[15] *See*, Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0, prepared by U.S. EPA, September 2009, pages 17 and 34.
Appendix B, pages B-3 and B-6.

these costs.

3.5 Cost TSD Section 2.6 – Escalation

We agree with EPA's assertion that the application of escalation is allowed by the CCM.[16] However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units.

Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013[17]. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services."[18] Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown in Table 6.

Table 6: Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown in Table 6, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that *de-escalated* costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.[19] Table 7 summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. We note that information from Alstom showed their pricing escalated nearly equivalently for

[16] *See* Cost TSD, Section 2.6, page 8

[17] Updated FGD pricing from Alstom is used as the basis of the 2015 cost estimate documented in S&L Report #012831.

[18] Escalation Indexes for Air Pollution Control Costs, United States Environmental Protection Agency, October 1995, pp. 3-4.

[19] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Entergy Costs"

equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible we applied the average 4.7% in the revised costs shown in Table 7. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Table 7: Summary of EPA's Escalation Errors (Per Unit)[20]

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Insurance @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs		$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA				**$42,607,547**

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

[20] *See* Cost TSD, Table 5 on page 10

3.6 Cost TSD Section 2.7 – Operating and Maintenance (O&M) Costs

Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."[21]

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia.[22] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems.[23] The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues.[24] The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not accounting for site-specific project and staffing needs;

[21] *See* Cost TSD, Section 2.7, page 9.
[22] *See*, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.
[23] *See*, e.g., IPM Model- Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Sargent & Lundy LLC, March 2013.
[24] *Id.*, at page 1.

- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and
- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Please see additional comments in the next section of our comments (3.7), addressing EPA's adjustment of the O&M cost estimates to account for lower coal sulfur.

3.7 Cost TSD Section 3.1 – Entergy's Coal Sulfur Assumption

EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a

design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Figure 1 illustrates why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient. The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

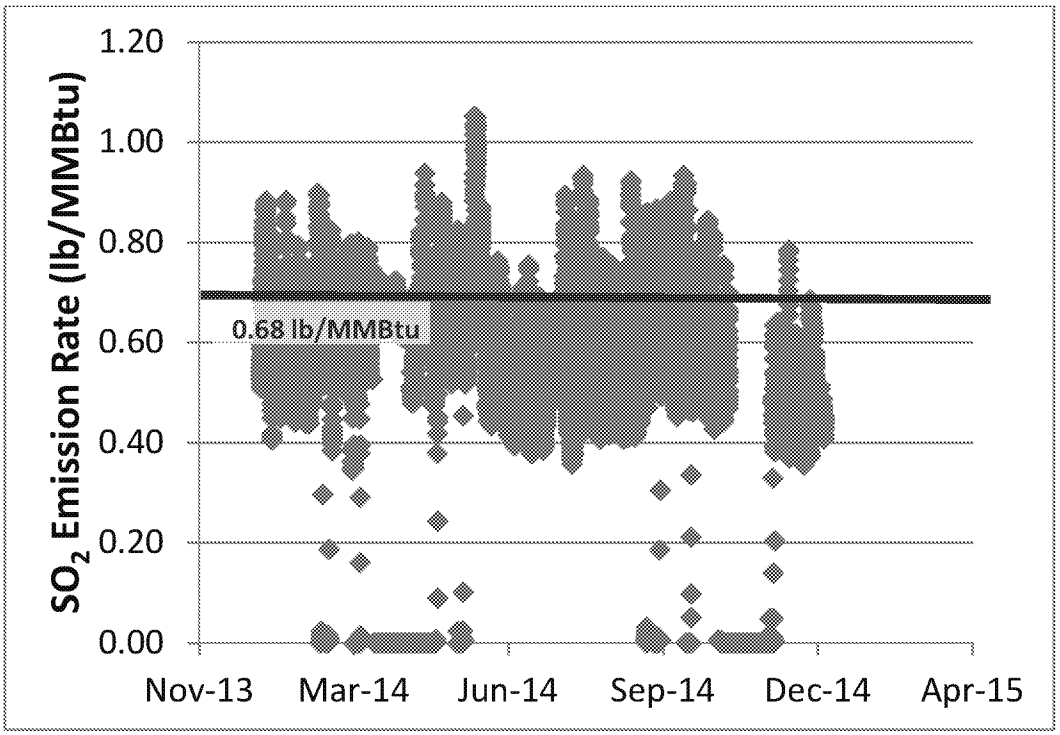


Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

While we believe that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in Figure 1 confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831.

As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being

[25] Downloaded from EPA's Clean Air Market Database.

included in its cost-effectiveness calculation.[26] This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost.[27] Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

3.8 Cost TSD Section 4.1 – EPA's Conservatism in Cost Estimating

EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers,"[28]and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

3.9 Remaining Useful Life

EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown."[29] Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls and White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of

[26] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Cost-Effectiveness" Cell D4.
[27] *Id.*
[28] Cost TSD, Section 4.1 page 16.
[29] AR FIP TSD, p. 80.

2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

4. Cost TSD Section 5 – Inclusion of Independence under Reasonable Progress Goals (RPGs)

EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility.[30] It is beyond the scope of S&L's comments to address the basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units."[31] EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source.[32] Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters[33]

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system;

[30] *See* 80 Fed. Reg. 18,991 (April 8, 2015).
[31] *Id.*, at page 18,992.
[32] *See* "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. EPA June 1, 2007, pg 1-3.
[33] *Id.*, at page 5-1.

therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;
- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines."[34] We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation."[35] EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv.[36] Considering that

[34] *Id.*, at page 5-1.
[35] *Id.*, at page 5-2.
[36] *See* 80 Fed. Reg. 18,998, Table 67.

Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NO_X emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. Table 8 shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Table 8: Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement[37]	0.08	0.07
Revised Annualized Costs[38]	$106,765,022	$106,765,022
$/Δdv	$1,334,562,775	$1,525,214,600

[37] The CENRAP modeling includes SO_2 and NO_X impacts; therefore, the numbers shown likely overestimate the visibility improvement based solely on SO_2 reductions.

[38] Annualized costs for Retrofitting Dry FGD at White Bluff 1 and 2 from S&L Report #012831 were used assuming a 30-year remaining useful life.

5. CONCLUSION

S&L reviewed the approach EPA takes in its proposed FIP for Arkansas, including EPA's determination of costs for retrofit dry FGD scrubbers, and EPA's evaluation of annual SO_2 emission reductions. Our analysis identifies several areas where EPA overstates the cost-effectiveness ($/ton of SO_2 removed) of the dry FGD retrofits that EPA would require in its FIP. As discussed in this analysis, cost-effectiveness is influenced by two variables: the total annualized cost to retrofit FGD controls ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. Table 9 shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Table 9: Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment*	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831)*	**$536,185,000**	**$109,681,936 to $122,657,613**
Differential from EPA FIP*	**+ $99,853,852**	**+ $54,993,838 to $63,400,600**

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, Table 10 shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Table 10: Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	**-99**	**-868**

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). Table 11 summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As Table 11 indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Table 11: Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831)*	**$7,689 to $8,599**	**$7,642 to $8,546**
Differential from EPA FIP[1]	**+ $5,462 to $6,372**	**+ $5,541 to $6,445**

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is **over $1.3 billion/Δdv** for Caney Creek and **over $1.5 billion/Δdv** for Upper Buffalo, which is clearly not cost effective.

White Bluff 1	EPA FIP	Corrected Baseline Emissions	Corrected Heat Input and Emission Reduction	Section 2.4, Excluded BOP Costs	Section 2.5, Excluded Owner's Costs	Section 2.6, Incorrect Escalation	Section 2.7, Corrected Operating Cost	Remaining Useful Lifetime Adjustment (7 Year Life)	Remaining Useful Lifetime Adjustment (6 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 7 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 6 Year Life)
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)[2]	0.65	0.65	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	Not Used	Not Used	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551
Controlled SO2 Emission Rate (%)	90.81	90.81	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	15,816	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939
SO2 Emission Reduction (tons)	14,363	14,474	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264
Cost Effectiveness ($/ton)	$2,227	$2,210	$2,242	$2,330	$2,566	$2,806	$3,540	$6,097	$6,687	$7,689	$8,599
White Bluff 2											
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)	0.68	0.68	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	49,108,824	47,158,824	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262
Controlled SO2 Emission Rate (%)	91.16	91.16	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	16,697	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034
SO2 Emission Reduction (tons)	15,221	14,617	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353
Cost Effectiveness ($/ton)	$2,101	$2,188	$2,228	$2,315	$2,550	$2,789	$3,518	$6,060	$6,646	$7,642	$8,546

1 - EPA did not list the heat input. EPA's analysis incorrectly assumes the annual averageheat input as being the baseline SO_2 emissions (tpy) divided by the monthly maximum emission rate (lb/MMBtu)

2- EPA incorrectly applied the maximum maximum monthly SO_2 emission rate to determine the % reduction in SO_2 to achieve 0.06

3- EPA did not include this item. SO_2 emission reduction is corrected to calculate it as [baseline annual average heat input (MMBtu/Yr)] * [the controlled SO_2 emission rate (lb/MMBtu)]*[2000 lb/ton]

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-012831
Final
July 14, 2015
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

EPA-HQ-2018-002296

LEGAL NOTICE

This report was prepared by Sargent & Lundy, L.L.C., hereinafter referred to as S&L, expressly for Gill Ragon Owen on behalf of Entergy Arkansas, Inc., hereinafter referred to as Entergy. Neither S&L nor any person acting on its behalf (a) makes any warranty, express or implied, with respect to the use of any information or methods disclosed in this report or (b) assumes any liability with respect to the use of any information or methods disclosed in this report.

Exhibit B to EAI Comments

ED_002110_00032342-00091

CONTENTS

Section **Page**

EXECUTIVE SUMMARY **1**

1. PURPOSE **1**

2. APPROACH **1**

2.1 TECHNOLOGY SELECTION 1

2.2 CONTRACTING APPROACH 1

2.3 CAPITAL COST DEVELOPMENT 2

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS **5**

3.1 DRY FGD ISLAND 5

3.2 REAGENT HANDLING SYSTEM 7

3.3 BYPRODUCT HANDLING SYSTEM 7

3.4 FLUE GAS HANDLING SYSTEM 8

3.5 ELECTRICAL BOP SYSTEM 8

3.6 I&C BOP SYSTEM 8

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS **10**

4.1 EPC CONTRACT PRICE 10

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE 19

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS 23

4.4 FIXED OPERATING AND MAINTENANCE COSTS 24

4.5 SULFUR DESIGN BASIS SENSITIVITY 24

5. SUMMARY **26**

6. ATTACHMENTS **27**

EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $1,072,370,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $10,166,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the

construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication
17	June 2018	Physical Flow Model Completed

Month	Date	Milestone
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were

included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the

new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.68 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.46% (based on Entergy's future operating profile).
- Compliance deadline of December 2020.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps
      - Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
   - Three absorber vessels per unit, with access doors
   - Rotary atomizers, two spare atomizers included
   - Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
   - Heating and ventilation
   - Vacuum piping
   - SDA Superstructure
   - Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
   - New baghouse, including pulse jet cleaning system and all appurtenances
   - Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
   - One recycle silo with bin vent filter per unit, 8-hour total capacity
   - Two recycle mix tanks per unit
   - Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
   - Agitators for each tank
   - Baghouse ash handling system common to both units
   - Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
   - Pneumatic pressure blowers (8 x 33⅓ %)
   - Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
   - Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
   - Includes motors - no spare motor included
   - Cost estimate based on budgetary proposal from Alstom
   - Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

2. <u>FGD Island Foundations and Enclosures</u>

   a. Absorber tower foundations including caissons

   b. Baghouse area foundations including 18" auger cast piles 60' long

   c. Booster fan area foundations

d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)

e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. Reagent Storage and Handling, common to both units:

a. Lime rail car unloader:

- Lime delivery via 25-car unit train
- System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
- Enclosed railcar unloading building
- One vacuum pneumatic system operating to unload a car
- Pneumatic vacuum exhausters (2 x 100%)
- Filter separator with vacuum-to-pressure transfer hopper and valves
- One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack
- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:

- Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
- 32' diameter and 95' height to top
- 1,200-tons storage, each
- Continuous level detection systems
- Bin vent filters
- Live bottom hopper outlets
- Rotary airlock assemblies

- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers (3 x 100%)
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. Byproduct Handling System, common to both units

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling System, per unit

a. ID fan outlet to absorber inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

b. Absorber outlet to baghouse inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

d. Concrete foundations for all flue gas ductwork

e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP

a. Roadwork

b. Site grading

c. Soil removal earthwork

d. Excavation, backfill, and compaction for all foundations

e. Storm sewer work

f. Two-cell pond for wastewater storage of process water/slurry

g. Laydown Area
   - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.

h. Highway Intersection Upgrade to provide sufficient plant access for construction period
   - New Bypass Lane on Westside of Highway 365
   - New Southbound Left Turn Lane on Highway 365
   - New Northbound Merge Lane on Highway 365
   - New Northbound Right Turn Lane on Highway 365
   - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
   - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
   - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing

i. New warehouse building 200' x 75' x 15', including substructure and superstructure.

7. Mechanical BOP System

a. Interconnecting piping, above-ground and buried

b. Valves for interconnecting piping, above-ground and buried

c. Lime slaking water storage tank, 115,000-gallon capacity

d. Slaker water 3" in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
   - Between lime railcar unloading enclosure and lime silos
   - Between lime silos and lime day bins
   - From baghouse hoppers to recycle silos and FGD by-product silo
   - From lime slurry storage tanks to absorber
   - From recycle slurry storage tank to absorber
   - Concrete foundations including caissons for all pipe racks
   - Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
   - Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150' TDH
   - Four reagent prep/recycle sump pumps, 120 gpm @ 150' TDH
   - Two lime silo and unloading area sump pumps, 120 gpm @ 150' TDH
   - Two by-product ash silo area sump pumps, 120 gpm @ 150' TDH
   - Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200' TDH
   - Two lime slaking water pumps, 750 gpm @ 100' TDH
   - One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100' TDH, including new intake structure, piping and valves
   - Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
   - Air compressors; 2 x 100%, 250 scfm each @ 100 psig
   - IA dryers w/filters; 2 x 100%, 250 net scfm each
   - Air receivers; 2 x 100%
   - Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
   - Heat-traced piping

i. Service Air System, common to both units
   - Air compressors; 2 x 100%
   - Air receivers; 2 x 100%

j. Field painting
   - Multiple coat system used for exposed ductwork only
   - Inorganic zinc primer and polyurethane system used for steel
   - Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation
   a. Hazardous material accumulation building
   b. Ash handling maintenance building
   c. Drainage ditch
   d. Pipe trench
   e. Fabrication shop
   f. Existing contractor electrical hook up
   g. Existing drainage ditches, rerouted with new concrete trenches
   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
   i. Rail Yard Extension, common to both units
      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
   j. Fire Protection System Modifications
      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System
   a. One 115-kV, 1200A isolation disconnect switch
   b. One startup transformer
   c. Two unit auxiliary transformers (UAT)
   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
   f. Two 480-V double ended switchgear buses per unit (total of four)
   g. Six 480-V motor control centers per unit (total of twelve)
   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
   i. Two isolated phase UAT tap bus extensions
   j. Non-segregated phase bus
   k. Medium-voltage cable
   l. Low voltage, control and instrumentation cable, as necessary
   m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

a. Controls System based on an estimated number of I/O points:

- Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
- Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

b. CEMS, per unit

- Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average

and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:
   - Project Development (through EPC Award) – 25 months, equivalent of 10 people
   - Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of

overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

a. Commissioning Support Specialists – 8 months, 2 people

The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

a. Conceptual Study Support
b. EPC Specification Supporting Documents
c. Project Schedule Development
d. EPC Specification Development
e. EPC Bid Evaluation and Contract Conformance
f. General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
h. Design Review of Drawing Submittals
i. Technical support during design, fabrication, construction, commissioning, and testing
j. Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol
b. Procuring the services of the testing contractor
c. Overseeing the performance test campaign
d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost	$/MWh	$43.35

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Design 0.68 lb SO_2/MMBtu
Dry FGD System Parameters		
Reagent Consumption	lb/hr	7,000
Byproduct Waste Production	lb/hr	16,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	75
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,888,000
Byproduct Waste Disposal Cost	$/year	$380,000
Aux Power Cost	$/year	$3,027,000
Water Cost	$/year	$214,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,881,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.46%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Design 0.68 lb SO_2/MMBtu
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.68 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.68 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue

gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.68 lb/MMBtu	Cost Reduction for 1.2 to 0.68 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,200 tons each	- $4,332,000
Two lime day bins	650 tons each	300 tons each	- $272,000

Two detention lime slakers	13 tons/hour each	7 tons/hour each	- $113,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $373,000
Two FGD by-product storage silos	3,000 tons each	1,750 tons each	- $2,400,000
		TOTAL Differential	**- $7,490,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.68 lb SO_2/MMBtu is approximately $7.5M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A

2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A

3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule

4. Monthly Progress Payment Schedule for White Bluff DFGD Project

5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates

6. S&L Estimating Documentation: Escalation Projections

7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing

8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	06/29/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387A
Cost index	ARPBL

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Project Cost Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	104,382,058		1,309,072
Material	64,284,799		
Subcontract	313,285,100		
Process Equipment	23,517,000		
	505,468,957	505,468,957	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	7,306,743		
91-2 Cost Due To OT 5-10's	14,545,500		
91-4 Per Diem	13,090,700		
91-5 Consumables	1,043,800		
91-6 Freight on Material	3,214,200		
91-8 Sales Tax	8,928,800		
91-9 Contractors G&A	20,987,700		
91-10 Contractors Profit	10,493,800		
	79,611,243	585,080,200	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	60,898,000		
	84,798,000	669,878,200	
Escalation:			
96-1 Escalation on Material	7,632,000		
96-2 Escalation on Labor	23,480,200		
96-3 Escalation on Subcontract	37,428,800		
96-4 Escalation on Process Eq	2,158,600		
96-5 Escalation on Indirects	12,334,500		
	83,034,100	752,912,300	
Total EPC Cost		***752,912,300***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	811,458,300	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	824,002,300	
Project Contingency :			
110 Project Contingency	111,145,700		
	111,145,700	935,148,000	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	937,421,000	
Interest During Construction:			
130 Interest During Constr.	134,949,000		
	134,949,000	1,072,370,000	
Total		***1,072,370,000***	

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,672,000	1,069,675	107,860	7,935,771	23,390,546
111	FLUE GAS SYSTEM		480,000	16,910,286	337,269	29,197,085	46,587,373
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,682,913	115,659	9,169,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	**313,285,100**	**23,517,000**	**64,284,799**	**1,309,072**	**104,382,058**	**505,468,956**

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU. Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			**FGD ISLAND**									
	23.00.00		STEEL									
		23.13.75	SILO									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				(273,000)		-690		(50,428)	(323,428)
			STEEL				(273,000)		-690		(50,428)	(323,428)
	31.00.00		MECHANICAL EQUIPMENT									
		31.45.00	FGD EQUIPMENT									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
			MECHANICAL EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			10 FGD ISLAND			**297,904,000**	**(1,649,000)**		**-7,814**		**(680,533)**	**295,574,467**
101			**FGD ISLAND FOUNDATIONS AND ENCLOSURES**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					961,632	13,324		1,445,136	2,406,768
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					1,043,634	14,211		1,541,379	2,585,013

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					2,005,266	27,536		2,986,515	4,991,781
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					1,204,900	11,798		779,520	1,984,420
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					5,402,720	38,437		3,560,015	8,962,735
			STEEL					6,607,620	50,235		4,339,534	10,947,154
	24.00.00		ARCHITECTURAL									
		24.17.00	ELEVATOR									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergen & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
31.00.00			MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
34.00.00			HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
36.00.00			INSULATION									
		36.13.00	DUCT									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergere & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 AS	6,000,000				59.71 /MH		6,000,000

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			**6,000,000**	**2,046,000**	**3,162,954**	**59,192**		**4,646,650**	**15,855,604**
105			**BYPRODUCT HANDLING SYSTEM**									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**1,089,675**	**107,800**		**7,935,771**	**23,610,546**
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			DUCTWORK					5,638,100	119,641		11,635,124	17,273,224
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			GIRDER					7,089,360	90,207		8,354,963	15,444,323
			STEEL					12,727,460	209,848		19,990,087	32,717,547
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES				480,000		2,943		286,161	766,161
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT					915,000	10,517		1,022,802	1,937,802
			MECHANICAL EQUIPMENT				480,000	915,000	13,460		1,308,963	2,703,963
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			111 FLUE GAS SYSTEM				**480,000**	**16,910,288**	**337,269**		**29,197,085**	**46,587,373**
121			**CIVIL BOP**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						28,506		5,197,453	5,197,453
		21.17.00	EXCAVATION									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						4,868		439,945	439,945
		21.19.00	DISPOSAL									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						483		38,288	38,288
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						172		13,674	13,674
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					110,000	2,299		165,839	275,839
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					1,065,011	3,448		335,555	1,400,566
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					3,346,203	19,569		1,533,638	4,879,841
		21.71.00	TRACKWORK									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			220,000						220,000
		21.99.00	CIVIL WORK, MISCELLANEOUS									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Burgess & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			220,000		5,301,214	68,540		8,453,679	13,974,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					93,638	1,311		89,786	183,423
			MECHANICAL EQUIPMENT					93,638	1,311		89,786	183,423
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					187,275	196		12,544	199,819
			HVAC					187,275	196		12,544	199,819
	36.00.00		INSULATION									
		36.99.00	INSULATION, MISCELLANEOUS									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					20,430	196		10,000	30,430
			INSULATION					20,430	196		10,000	30,430
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					187,275	196		12,452	199,727
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					100,000	230		18,862	118,862
			ELECTRICAL EQUIPMENT					287,275	426		31,314	318,589
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			350,000						350,000
			PROJECT INDIRECT			350,000						350,000
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						517		41,022	41,022
			DEMOLITION						517		41,022	41,022
	21.00.00		CIVIL WORK									
		21.17.00	EXCAVATION									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,675	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684

Exhibit B to EA Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					156,460	6,154		646,677	803,138
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					690,804	9,407		1,020,272	1,711,076
			CIVIL WORK					847,264	17,561		1,666,949	2,514,214
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					94,530	3,307		197,455	291,985
			CONCRETE					94,530	3,307		197,455	291,985
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					653,110	4,709		436,166	1,089,276
			STEEL					653,110	4,709		436,166	1,089,276
	27.00.00		PAINTING & COATING									
		27.13.00	COATING									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			270,000						270,000
			PAINTING & COATING			270,000						270,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				709,200		405		27,707	736,907
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		151,519	279,019
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				220,000		368		23,404	243,404

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	PUMP									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				1,039,800		3,998		273,763	1,313,563
		31.83.00	TANK									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			728,000						728,000
			MECHANICAL EQUIPMENT			728,000	1,039,800	127,500	8,729		476,392	3,300,892
35.00.00			PIPING									
		35.13.01	SS 304, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					198,156	7,494		579,755	777,911
		35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					609,874	36,441		2,819,087	3,428,961
		35.13.36	DUCTILE IRON, ABOVE GROUND, PROCESS AREA									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					162,000	3,594		259,256	421,256
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					127,845	4,471		345,897	473,742
		35.15.10	CARBON STEEL, BURIED									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	CARBON STEEL, BURIED									
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					912,807	19,533		1,511,045	2,423,852
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					50,024	1,554		120,219	170,243
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					33,640	2,413		186,633	220,273
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					81,550	1,071		82,873	164,423
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					2,860,785	4,228		327,099	3,187,884
			PIPING					5,036,681	86,799		6,231,866	11,268,547
36.00.00			INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,865		127,914	175,408
			INSULATION					47,494	1,865		127,914	175,408
41.00.00			ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					76,334	177		11,256	87,590
			ELECTRICAL EQUIPMENT					76,334	177		11,256	87,590

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**
190			**DEMOLITION / RELOCATION**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						2,732		222,400	222,400
		11.22.00	CONCRETE									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						1,049		112,307	112,307
		11.23.00	STEEL									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						359		38,408	38,408
		11.24.00	ARCHITECTURAL									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						1,801		192,854	192,854
		11.31.00	MECHANICAL EQUIPMENT									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						290		26,852	26,852
		11.35.00	PIPING									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						162		17,401	17,401
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						2,299		212,920	212,920
			DEMOLITION						8,691		823,142	823,142
	21.00.00		CIVIL WORK									
		21.16.00	GENERAL EARTHWORK									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK					100,800	856		156,133	256,933

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,280	3,002		353,080	788,280
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,873		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					37,500	523		35,814	73,314
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					80,000	575		39,356	119,356
			MECHANICAL EQUIPMENT					117,500	1,755		132,736	250,236
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					46,200	48		3,094	49,294
			HVAC					46,200	48		3,094	49,294
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					1,806	45		3,518	5,323
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					12,660	400		30,944	43,604
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					6,913	191		14,761	21,674
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					160	66		5,122	5,282
			PIPING					21,539	702		54,344	75,883
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					126,500	132		8,411	134,911
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					14,700	55		3,511	18,211
			ELECTRICAL EQUIPMENT					141,200	187		11,921	153,121
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					258	4		266	524

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	DUCT BANK									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					585,000	107,471		6,646,649	7,236,649
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					645,120	18,538		1,521,037	2,166,157
		43.20.00	600V CABLE & TERMINATION									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					1,881,340	30,069		2,467,159	4,348,499
		43.40.00	5/8KV CABLE & TERMINATION									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					5,713,230	33,903		2,781,778	8,495,008
		43.50.00	15KV CABLE & TERMINATION									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					206,721	5,895		483,718	690,439
			CABLE					8,446,411	88,406		7,253,692	15,700,103
	51.00.00		SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
		51.15.27	CIRCUIT BREAKER									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	DISCONNECT SWITCH									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					15,000	69		3,847	18,847
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					15,000	69		3,847	18,847
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.13.00	CONTROL SYSTEM									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				1,500,000		2,299		148,690	1,648,690
		44.21.00	INSTRUMENT									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					578,000	7,946		651,967	1,229,967
		44.25.00	MONITORING EQUIPMENT									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Bergeron & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow

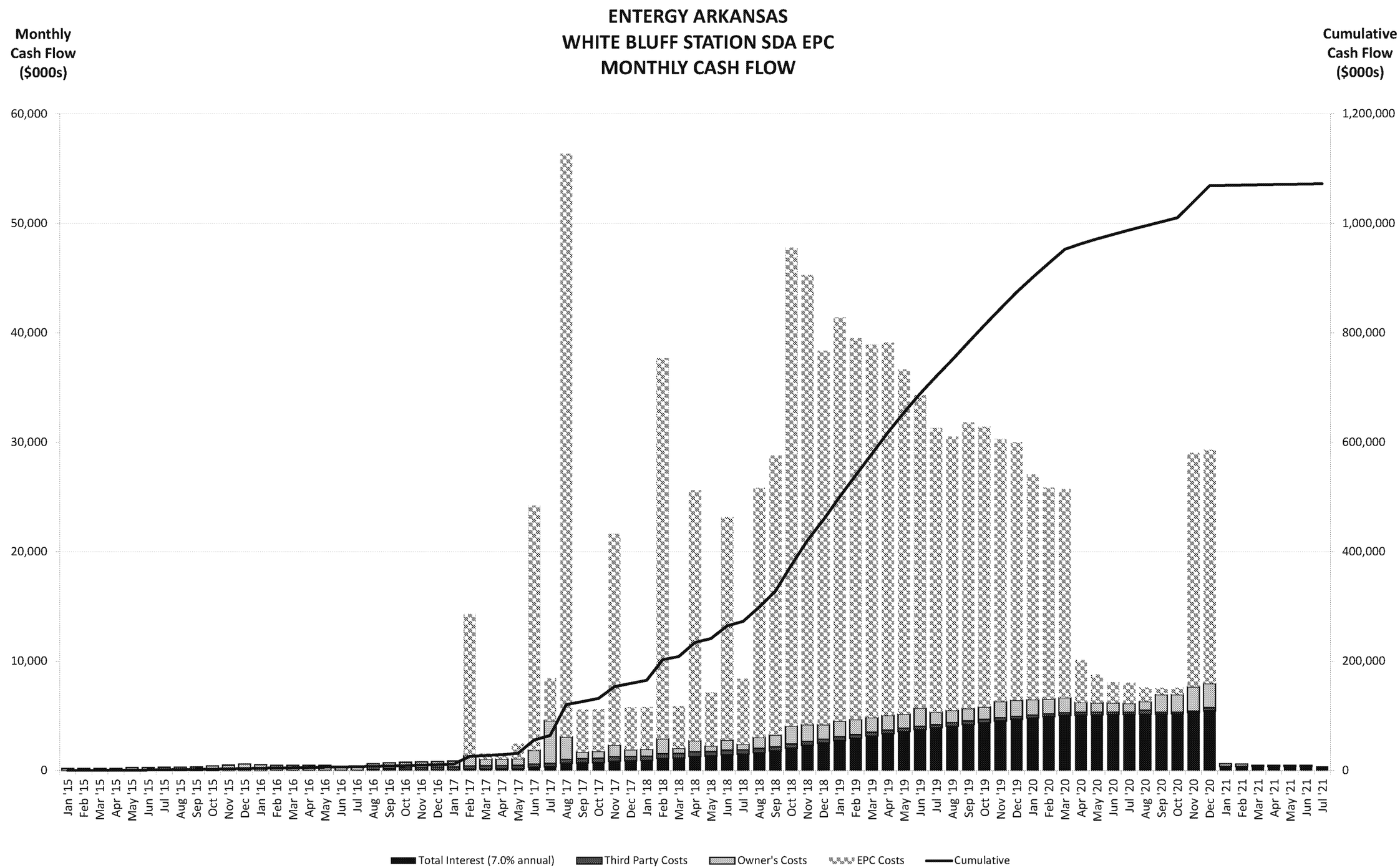


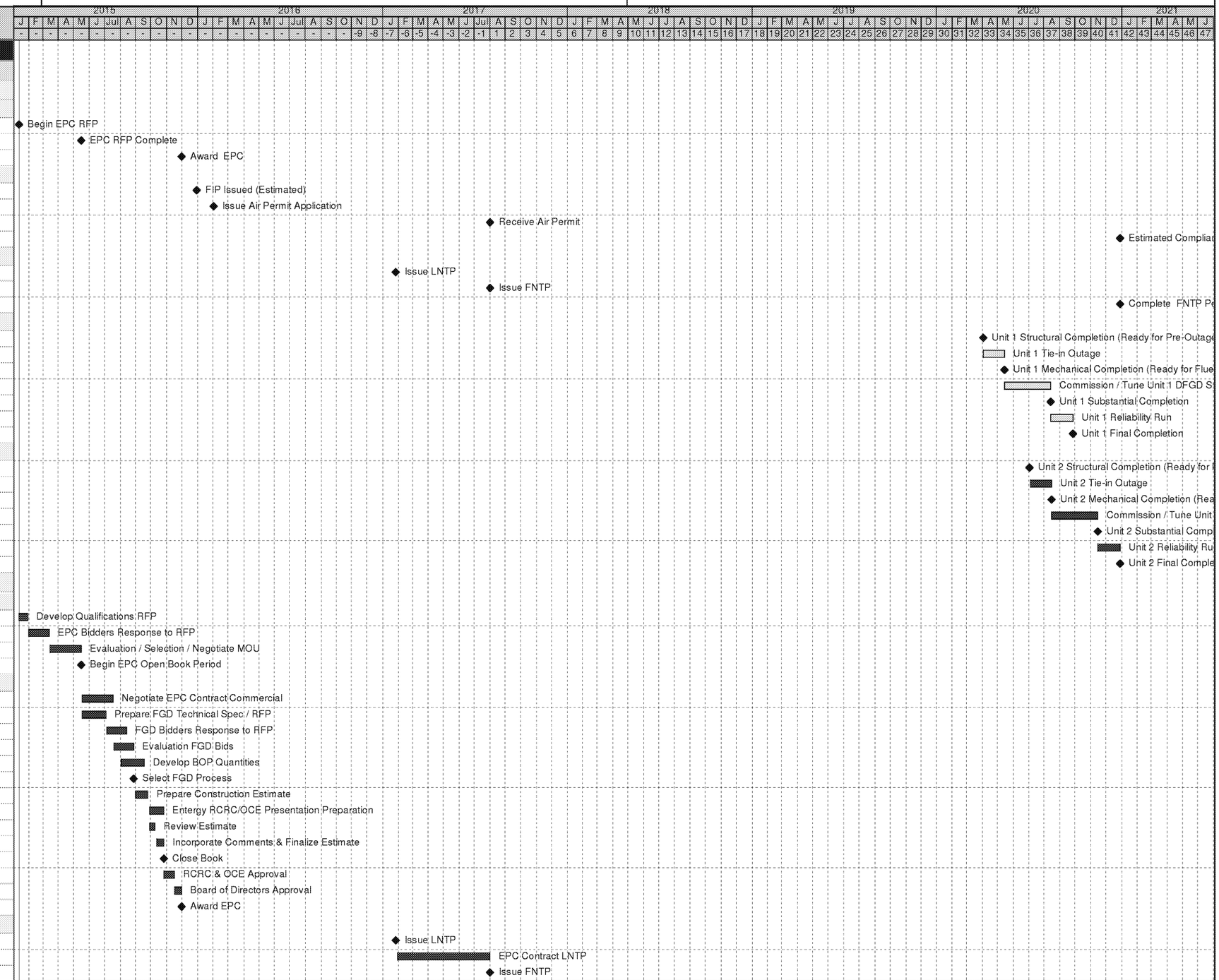
Exhibit B to EAI Comments

ATTACHMENT 3

Level 1 Preliminary Execution Schedule

WHITE BLUFF FGD SCHEDULE (December 2020) 29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17



Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

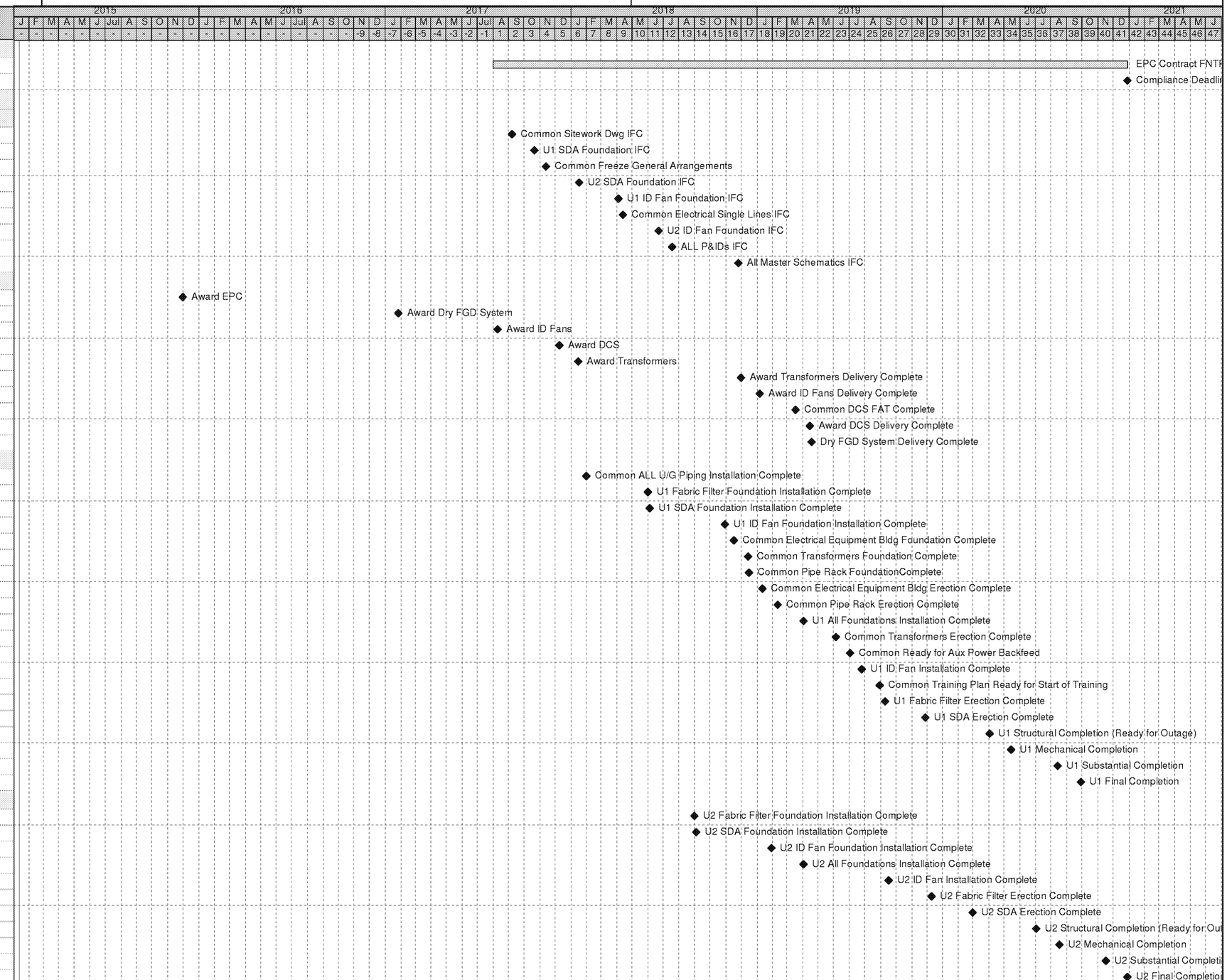
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020) 29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20



Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

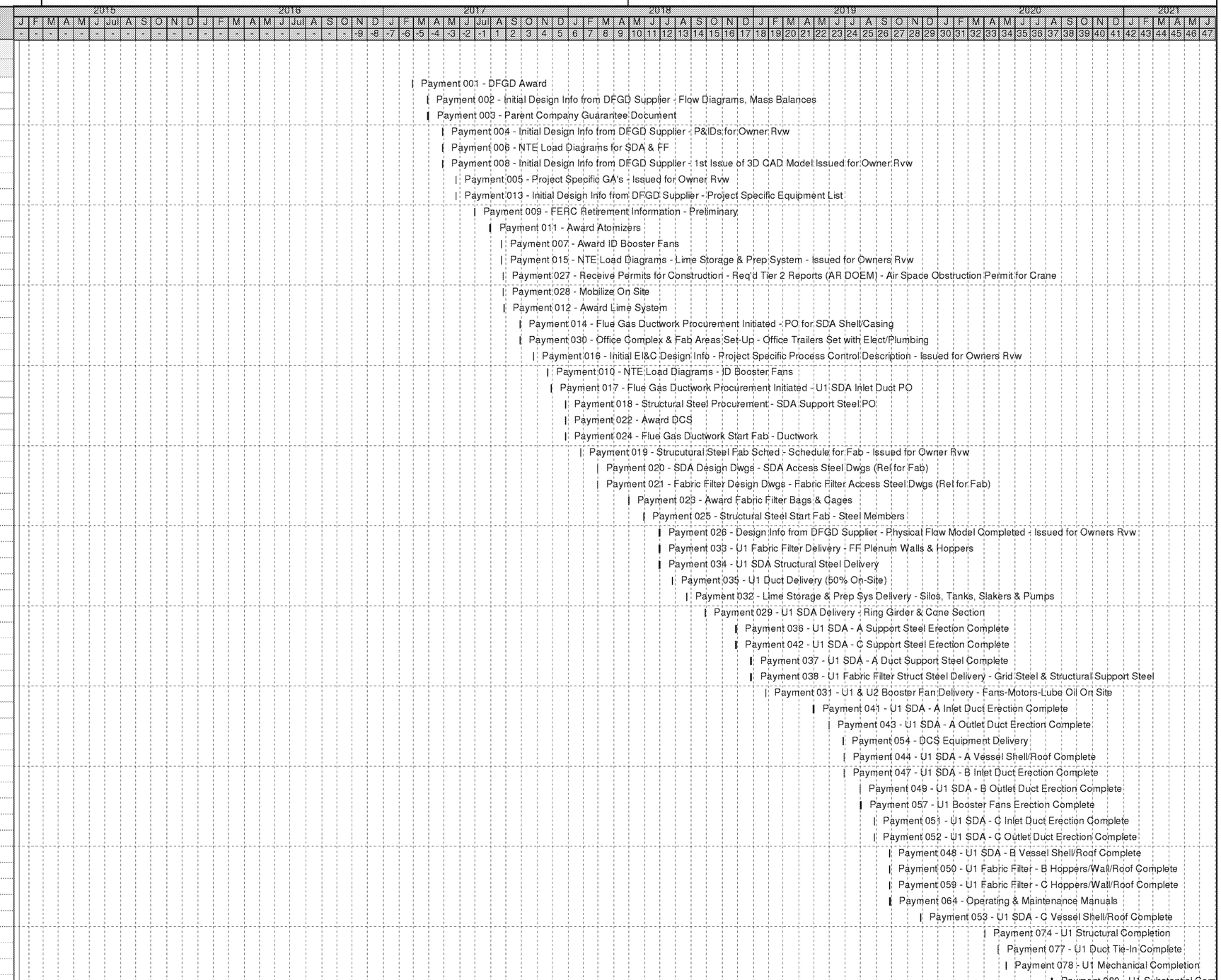
TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020) | 29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

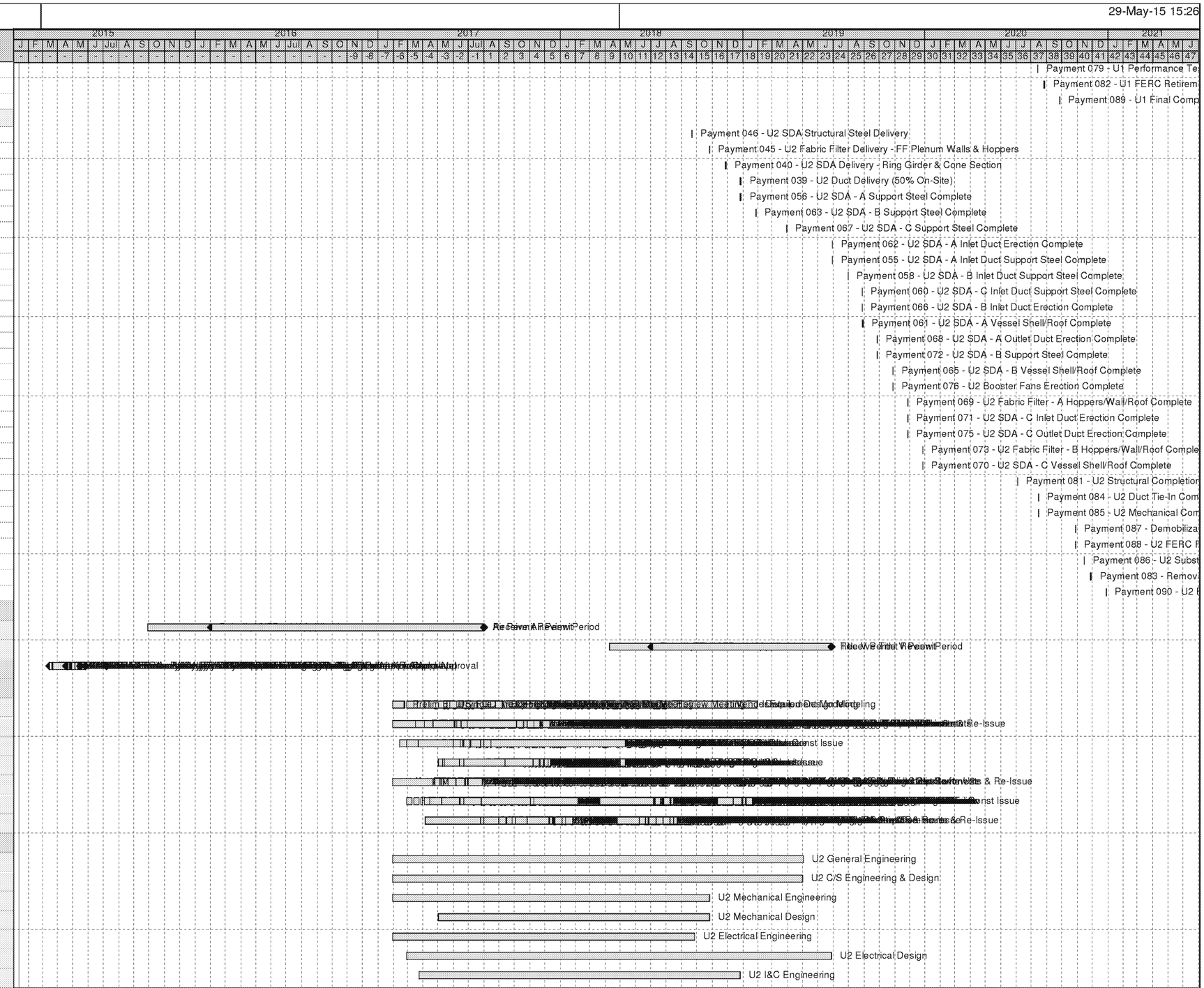
(c) Primavera Systems, Inc

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

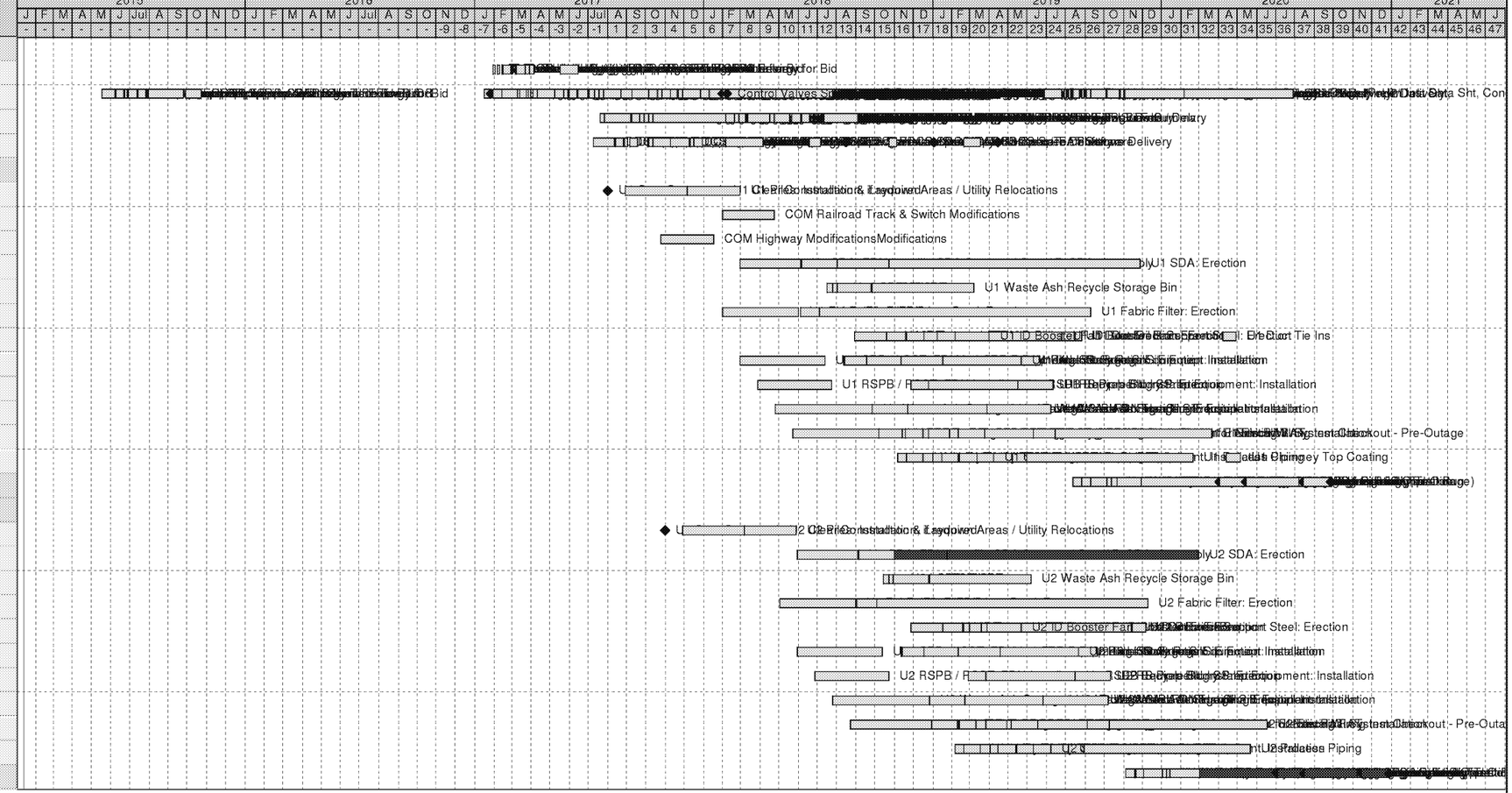
(c) Primavera Systems, Inc

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
Procurement		1357	18-May-15	28-Jul-20
C/S/A Procurement		98	30-Jan-17	15-Jun-17
Mechanical Procurement		1357	18-May-15	28-Jul-20
Electrical Procurement		347	20-Jul-17	30-Nov-18
I&C Procurement		448	10-Jul-17	15-Apr-19
U1 Construction		720	02-Aug-17	05-May-20
U1 Sitework		150	02-Aug-17	27-Feb-18
U1 Railroad Track & Switch Mods		60	31-Jan-18	24-Apr-18
U1 Highway Mods		60	25-Oct-17	16-Jan-18
U1 SDA		457	28-Feb-18	28-Nov-19
U1 Field Fabricated Tanks		170	16-Jul-18	08-Mar-19
U1 Fabric Filter		419	31-Jan-18	09-Sep-19
U1 ID Booster Fans / Ductwork		436	29-Aug-18	29-Apr-20
U1 Lime Slurry		343	28-Feb-18	21-Jun-19
U1 Recycle Slurry		337	29-Mar-18	12-Jul-19
U1 Byproduct Handling		314	25-Apr-18	08-Jul-19
U1 Auxiliary Power		478	23-May-18	20-Mar-20
U1 Balance of Plant		390	07-Nov-18	05-May-20
U1 System Testing and Commissioning		294	13-Aug-19	27-Sep-20
U2 Construction		686	01-Nov-17	17-Jun-20
U2 Sitework		150	01-Nov-17	29-May-18
U2 SDA		458	30-May-18	28-Feb-20
U2 Field Fabricated Tanks		170	15-Oct-18	07-Jun-19
U2 Fabric Filter		419	02-May-18	09-Dec-19
U2 ID Booster Fans / Ductwork		268	28-Nov-18	07-Dec-19
U2 Lime Slurry		343	30-May-18	20-Sep-19
U2 Recycle Slurry		337	28-Jun-18	11-Oct-19
U2 Byproduct Handling		314	25-Jul-18	07-Oct-19
U2 Auxiliary Power		476	22-Aug-18	17-Jun-20
U2 Balance of Plant		337	06-Feb-19	21-May-20
U2 System Testing and Commissioning		301	05-Nov-19	29-Dec-20



Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

(c) Primavera Systems, Inc

Exhibit B to EAI Comments

ATTACHMENT 4

Milestone Progress Payment Schedule

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings	0.16	1.79
		NTE Load Diagrams		
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model	2.62	4.41
		Award Booster Fans		
6	Jul-17	NTE Load Diagrams	0.45	4.86
		Award Atomizers		
7	Aug-17	DFGD Supplier - Equipment Lists	6.24	11.10
		Award Lime System		
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information	0.45	12.00
		NTE Load Diagrams		
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages	2.68	22.36
		Flue Gas Ductwork Start of Fabrication		
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery	2.99	31.67
		Office Complex and Fabrication Areas Set-Up		
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery	5.12	36.79
		Lime Storage and Preparation System Delivery		
		Unit 1 Fabric Filter Delivery		
22	Nov-18	Unit 1 SDA Structural Steel Delivery	4.81	41.60
		Unit 1 Duct Delivery		
		Unit 1 SDA-A Support Steel Erection Complete		
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete	4.00	45.60
		Unit 1 Fabric Filter Structural Steel Delivery		
		Unit 2 Duct Delivery		
24	Jan-19	Unit 2 SDA Delivery	4.32	49.92
		Unit 1 SDA-A Inlet Duct Erection Complete		
		Unit 1 SDA-C Support Steel Erection Complete		
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete	4.08	54.00
		Unit 1 SDA-A Vessel Shell/Roof Complete		
		Unit 2 Fabric Filter Delivery		
26	Mar-19	Unit 2 Structural Steel Delivery	3.99	57.99
		Unit 1 SDA-B Inlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy Arkansas, Inc.

Entergy
White Bluff DGFD Project
Escalation Projections

SL-012831

Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

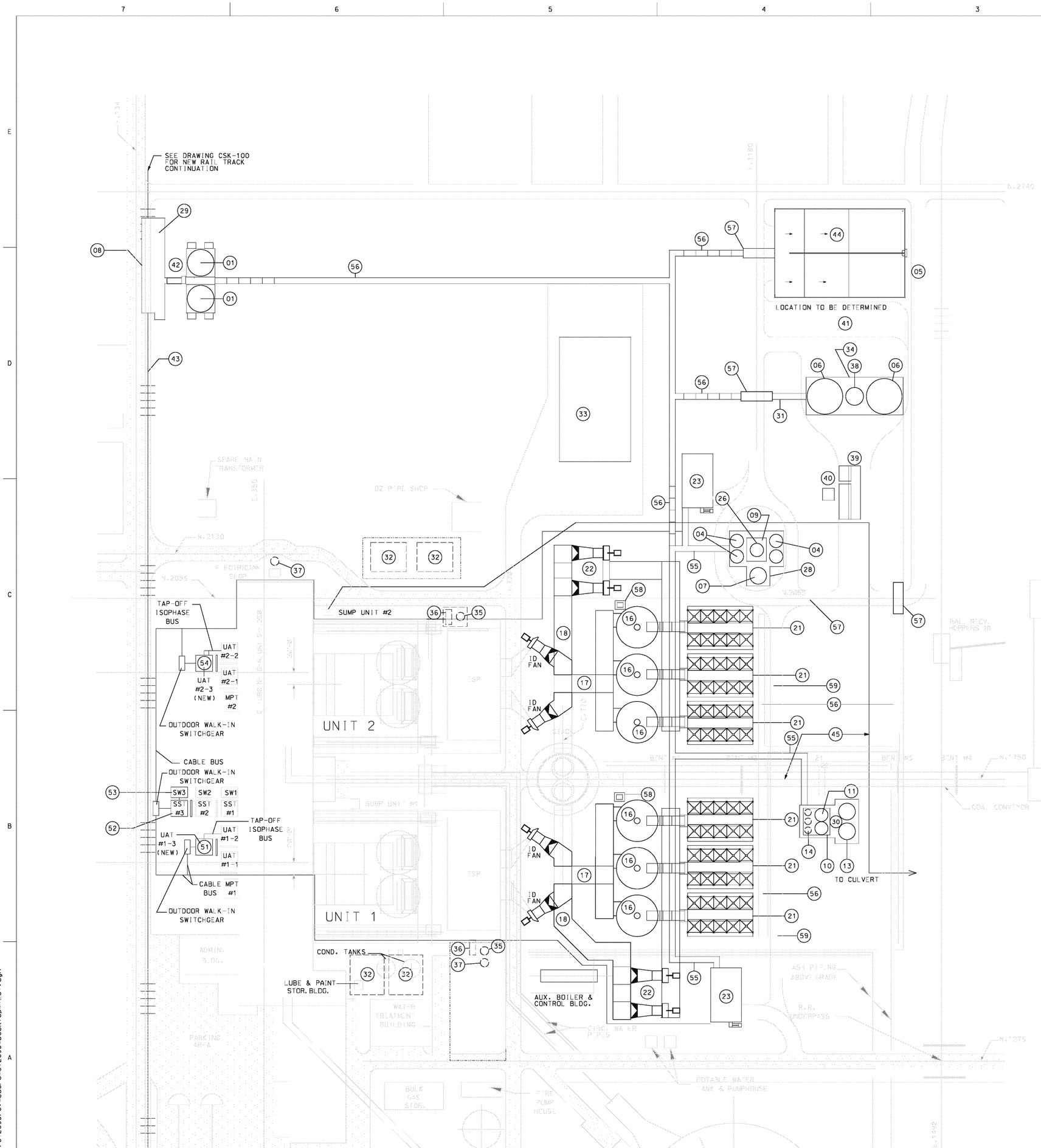
Misc Material and Equipment (Please see Note 1)									% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index									8%	15%	17.00%
Material Price, Construction Mat.									8%	7%	10.00%
Plant Cost Index									no increase	slightly negative	5.00%
Civil Work									8%	14%	15.00%
Steel - ductwork									no increase	slightly negative	8.00%
Steel - rolled shape									8%	no increase	10.00%
Architectural									5%	4%	8.00%
Overall mechanical equipment									4%	1%	7.00%
Overall piping									6%	11%	12.00%
Overall electrical equipment									9%	17%	18.00%
Raceway, Cable Tray, & Conduit									8%	slightly negative	10.00%
Electrical cable									14%	7%	15.00%
Controls & Instrumentation									1%	1%	5.00%
Average overall increase for Power back-fit projects									**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

Sargent & Lundy

ATTACHMENT 7

Conceptual General Arrangement Drawing



LEGEND

01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

PRELIMINARY
NOT FOR
CONSTRUCTION

NORTH

60′ 0 60′ 120′ 180′
GRAPHIC SCALE
DRAWING SCALE
1″ = 60′-0″

HOLD INFORMATION

NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: –

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

DRAWING NUMBER	REVISION
M-GA-001	N/A
SHEET 1 OF 1	

ZL8346/0-2695/C:*Users*0-2695*Desktop*TEST.dgn

5/28/2015 6:25:24 PM ...*Users*0-2695*Desktop*TEST.dgn

Exhibit B to EAI Comments

ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	$ 740,968,200				
	P90	P80	P70	P60	P50
Risk Contingency	$ 35,870,000	$ 27,220,000	$ 20,550,000	$ 16,210,000	$ 13,090,000
Estimate Uncertainty Contingency	$ 95,350,000	$ 66,600,000	$ 41,540,000	$ 21,330,000	$ (290,000)
Unknown Risk Contingency	$ 18,560,000	$ 17,380,000	$ 16,450,000	$ 15,610,000	$ 14,810,000
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			Resulting Range	
Estimate class	Maturity level of project definition expressed as % of complete engineering	End usage typical purpose of estimate	Methodology typical estimating method	Estimate accuracy range typical variation in low & high ranges	Target contingency range
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

WB FGD Project

Risk Register

ESTIMATE UNCERTAINTY							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project

Risk Register

UNKNOWN RISK							
Risk Category	Description of Risk	Quantitative Risk Analysis					Status / Comments
		Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

WB FGD Project

Risk Register

IDENTIFIED RISKS																	
				SCORING							Quantitative Risk Analysis						
Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project

Risk Register

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

REGIONAL HAZE MODELING ASSESSMENT REPORT

Entergy Arkansas, Inc. > Independence Plant

Entergy®

THE POWER OF PEOPLE™

Prepared By:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit C to EAI Comments

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. REGIONAL HAZE MODELING METHODOLOGY 2-1

2.1. EPA Photochemical Modeling Platform 2-1

2.1.1. Modeling Domain 2-1

2.1.2. Emissions Inventory 2-2

2.1.3. Other CAMx Input Data 2-2

2.2. Entergy Scenario One – Baseline Scenario 2-3

2.2.1. Emissions Inventory Updates 2-3

2.3. Entergy Scenario Two – Entergy's Proposed Control Approach 2-3

2.3.1. Emissions Inventory Updates 2-4

2.4. Entergy Scenario Three – Proposed Arkansas FIP Scenario 2-4

2.4.1. Emissions Inventory Updates 2-4

3. ANALYSIS OF RESULTS 3-1

3.1.1. Introduction to Atmospheric Visibility 3-1

3.1.2. MATS Processing 3-2

3.1.3. PSAT Source Contribution Analysis 3-3

3.1.4. Uniform Rate of Progress Curve Analysis 3-5

APPENDIX A: MODELED EMISSION RATES A-1

LIST OF FIGURES

Figure 2-1. EPA and ENVIRON Photochemical Modeling Platform Domain 2-2

Figure 3-1. Contribution Analysis Results for the Baseline Modeling Scenario at the Caney Creek Wilderness Area 3-4

Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area 3-5

Figure 3-3. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Caney Creek Wilderness Area 3-6

Figure 3-4. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Upper Buffalo Wilderness Area 3-7

APPENDIX: LIST OF TABLES

Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units A-1

1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published a proposed Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the proposed Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) that the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) for Class I areas in Arkansas and reasonable progress control requirements to achieve these RPGs. Specifically, the EPA proposed to meet RPGs by presenting two options for controlling emissions from the Entergy Arkansas, Inc. (Entergy) Independence Plant, which is not subject to BART.

In order to assess the reasonableness of the proposed control options for Electric Generating Units (EGUs) 1 and 2 at the Entergy Independence Plant (Independence units), as well as the EGUs at Entergy's White Bluff Plant (White Bluff units), the Comprehensive Air Quality Model with Extensions (CAMx) was used to perform regional haze modeling. This analysis was based on the CAMx regional haze modeling originally performed by the Central Regional Air Planning Association (CENRAP).

This report has been prepared to describe the modeling methodology used to evaluate Entergy's proposed control measures for emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) from the Independence and White Bluff units, as alternatives to the EPA's proposed control options. Entergy proposes a comprehensive approach to regional haze, involving the installation of low NO_X burners (LNB) and separated overfire air (SOFA) and a reduction in permitted SO_2 emission rates for the Independence units and White Bluff units, and the cessation of coal combustion at White Bluff by 2028. In addition to Entergy's proposed control scenario, the controls proposed in the Arkansas FIP were also evaluated using CAMx so that the expected visibility improvements from each scenario could be compared to EPA's proposed controls. The modeling methodology was developed in accordance with the original CENRAP modeling and takes into account Arkansas's two Class I areas, the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. REGIONAL HAZE MODELING METHODOLOGY

The regional haze assessment involves the determination of the total light extinction, the contribution of each selected emissions source to the total light extinction, and an analysis of the uniform rate of progress (URP) curves for Caney Creek and Upper Buffalo. This regional haze modeling analysis was performed using the advanced photochemical modeling software CAMx. The CAMx modeling system is a publicly available computer modeling system for the integrated assessment of photochemical and particulate air pollution. A description of the modeling files, domain, model simulation steps, and analysis methodologies are discussed in detail in the following subsections.

2.1. EPA PHOTOCHEMICAL MODELING PLATFORM

This analysis builds on the modeling of 2002 and 2018 emissions conducted previously by CENRAP and subsequently updated by ENVIRON for the EPA to aid in the development of the EPA's proposed Oklahoma and Texas Regional Haze FIP.[2] ENVIRON's 2018 baseline scenario is based on input data originally developed by CENRAP and enhanced by ENVIRON to provide higher resolution results and to accommodate more recent versions of CAMx and associated pre-processors. 2018 emissions data used in this baseline scenario were projected with growth and control factors from the 2002 emissions data obtained from the 2002 National Emissions Inventory (NEI).[3]

2.1.1. Modeling Domain

Figure 2-1 below presents the modeling domain used in the CENRAP regional haze assessment. This nested grid configuration of the CAMx domain includes the following grids:

- RPO_36km: This grid contains 36 kilometer (km) grid cells covering all of the continental U.S., along with southern Canada, northern Mexico, and portions of the Gulf of Mexico, Atlantic Ocean, and Pacific Ocean.
- Regional_12km: This nested grid contains 12 km grid cells covering all of Texas, Arkansas, and Louisiana, a majority of Oklahoma, and parts of Mississippi, Tennessee, Missouri, and New Mexico.

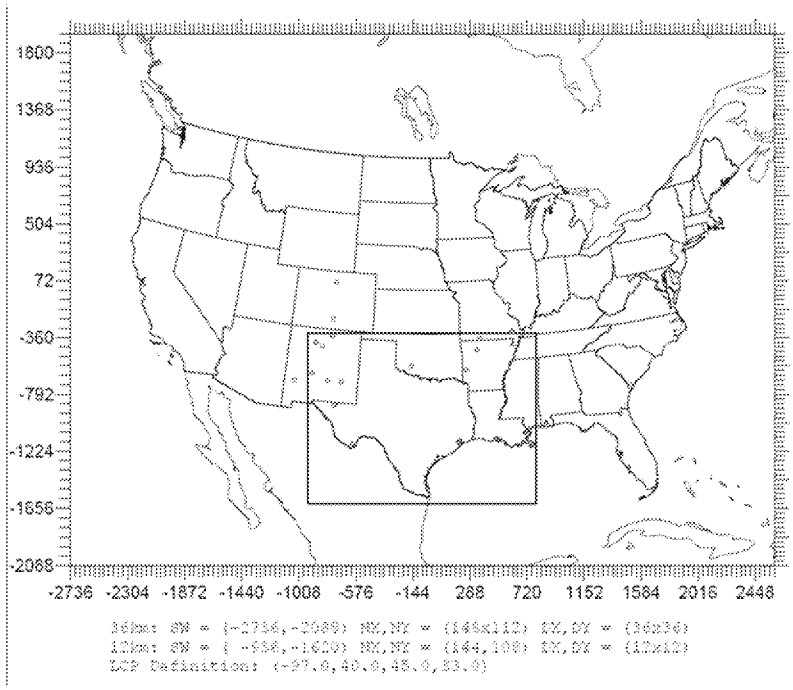
All modeling domain grids are projected in the Lambert Conformal Conic (LCC) map projection. The 36 km grid is also the domain used by the Regional Planning Organizations (RPOs) of which CENRAP is an example. The 12 km grid was developed by ENVIRON to allow for minimizing the effects of the boundary conditions on the 12 km grid since the boundary condition information is passed from the 36 km to the 12 km grid. The modeling domain contains locations of Interagency Monitoring of Protected Visual Environments (IMPROVE) sites which correspond to the Arkansas Class I areas, Caney Creek and Upper Buffalo, which are under consideration in the assessment of RPGs in the Arkansas FIP.

---

[2] Snyder, Erik, Michael Feldman, and Joe Kordzi. "Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans." U.S. EPA. November 2014.

[3] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

Figure 2-1. EPA and ENVIRON Photochemical Modeling Platform Domain[4]



2.1.2. Emissions Inventory

The CAMx model requires emissions in an hourly, speciated format. The Sparse Matrix Operator Kernel Emissions (SMOKE) pre-processor is used to process emissions data of various types of regional haze precursor emissions into a temporally and spatially allocated format. The SMOKE emissions pre-processor was configured to match the EPA's specifications and then used to process the emissions inventories used in this assessment. Version 3.1 of SMOKE was utilized in this analysis to be consistent with the EPA. The 2018 baseline scenario emissions data was used as the basis for this analysis. Each of the modeling scenarios required specific updates to the Arkansas FIP selected sources; therefore, these emissions points were updated in inventories separately from the other point source inventories and were merged into a single CAMx inventory file once SMOKE processing was complete.

2.1.3. Other CAMx Input Data

The remaining input data required to run CAMx, including but not limited to meteorological data, land-use files, albedo-haze-ozone inputs, photolysis rates, boundary and initial conditions, were unchanged from the original 2018 baseline scenario files.[5]

---

[4] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

[5] Nopmongcol, Uarporn and Greg Yarwood. Memo to Ellen Belk, EPA Region 6. "2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation." February 21, 2013.

2.2. ENTERGY SCENARIO ONE - BASELINE SCENARIO

The purpose of the baseline scenario is to develop a baseline level of total modeled light extinction at Caney Creek and Upper Buffalo. Additionally, the CAMx Particulate Source Apportionment Tool (PSAT) was used to trace the specific impacts of the Independence and White Bluff units as well as the remaining Arkansas sources subject to BART. In this way, the uncontrolled contribution of each source could be determined. As additional modeling is performed, the contributions of equipment from each scenario can be compared against the baseline contributions to determine the relative improvement or deterioration in visibility that can be expected due to application of various control options.

2.2.1. Emissions Inventory Updates

This regional haze assessment was based on the 2018 baseline scenario performed by ENVIRON. ENVIRON obtained the 2018 emissions inventory developed by CENRAP and incorporated selected updates, including but not limited to the addition of several new units and one new facility, the removal of several shutdown units, and the update of emission rates due to recently installed controls on selected units. Additionally, ENVIRON incorporated updates specific to the Oklahoma and Texas FIP determinations.[6]

It was noted during Entergy's initial review of these emissions inventories that two of the Arkansas sources subject to BART were not present. These two sources were the Entergy Lake Catherine Unit 4 (Lake Catherine unit) and the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station Unit 1 (Bailey Station unit). It is believed that the growth and control factors originally used by CENRAP to project the 2018 emissions inventory may be responsible for the proposed removal of the Bailey Station unit while the Lake Catherine unit appears to have been excluded from the original CENRAP modeling. Therefore, these two units were added into the emissions inventory for Entergy's baseline scenario.

Further review of the CENRAP inventories also indicated that the stack parameters for some of the Arkansas sources subject to BART were no longer representative of actual operations. The geographic coordinates of several sources, including the Independence and White Bluff units, were likewise found to point to inaccurate locations. The stack parameters and source locations of the Arkansas sources subject to BART were therefore updated to more accurately represent the current stack characteristics.

Additionally, since the growth and control factors estimated controlled emission rate values for the Arkansas FIP selected sources, it was necessary to revise the emission rates of these sources with uncontrolled values. The Arkansas sources subject to BART, excluding the White Bluff units, were given emission rates equal to the pre-controlled values based on the 2002 NEI data. The five selected Entergy units (from the Independence Plant, the White Bluff Plant, and the Lake Catherine Plant) were updated with revised emission rates provided by Entergy representing the uncontrolled actual emissions.

A table summarizing the emission rates of the Entergy units modeled in each scenario is included in Appendix A.

2.3. ENTERGY SCENARIO TWO - ENTERGY'S PROPOSED CONTROL APPROACH

With this modeling scenario, Entergy intends to determine the expected visibility benefits of the proposed alternative to the Arkansas FIP's determinations. As discussed in earlier sections, the proposed alternative scenario includes the installation of interim controls (e.g., LNB/SOFA) on the Independence and White Bluff

[6] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

units, the reduction of SO_2 emissions, and the ultimate cessation of coal combustion at the White Bluff facility. For the purposes of this assessment, control efficiencies were applied to the NO_X and SO_2 emissions rates for the Independence units while all White Bluff emissions sources were removed from the emissions inventories to signify the cessation of coal combustion.

2.3.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) served as the basis for Entergy's Proposed Scenario. Specific emissions inventory updates include the removal of all White Bluff Plant point sources from the emissions inventories and the revision of the emission rates of Entergy's Independence units and the Arkansas sources subject to BART. The Arkansas BART sources were modeled with the proposed post-control emission rates identified in the Arkansas FIP while the Independence units were modeled with the limited control efficiencies proposed by Entergy.

2.4. ENTERGY SCENARIO THREE - PROPOSED ARKANSAS FIP SCENARIO

The purpose of the Proposed Arkansas FIP Scenario is to determine the projected regional haze impacts of applying the controls proposed to be required by the Arkansas FIP. Therefore, all Arkansas sources determined to be subject to BART and the Independence units were modeled with the control rates proposed in the Arkansas FIP.

2.4.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) also served as the basis for the Proposed Arkansas FIP Scenario. Specific inventory updates include the revision of the emission rates of all Arkansas BART sources and the Independence units to the proposed post-control emission rates identified in the Arkansas FIP.

3. ANALYSIS OF RESULTS

CAMx model outputs were post-processed and analyzed to determine the visibility effects of each of the Arkansas FIP sources. In order to obtain comparable results to EPA's CAMx modeling, the same post-processing approach was utilized, which involves the conversion of binary CAMx output files into a readable format, the extraction of relevant regional haze pollutant concentration information, and the calculation of relative response factors (RRF) using EPA's Modeled Attainment Test Software (MATS). Calculation workbooks also provided by the EPA were then used to determine visibility impacts. The full post-processing procedure used to analyze each modeling scenario is discussed in detail below.

3.1.1. Introduction to Atmospheric Visibility

The primary purpose of the Regional Haze Rule is to improve visibility at mandatory Class I areas. In practical terms, visibility at Class I areas is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This scattering of light waves is called Rayleigh scattering. In eastern areas of the United States, it is estimated that without the effects of anthropogenic pollution, visibility is naturally limited to a distance of approximately 90 miles, while in western areas the natural visible range is approximately 140 miles.[7]

As atmospheric concentrations of particles and molecules increase, the level of visibility further decreases since light waves can potentially interact with a larger number of obstacles at equivalent distances. Therefore, pollution from both anthropogenic and non-anthropogenic sources can have a significant effect on visibility in Class I areas. The primary contributors to visibility impairment include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[8, 9]

In addition to visual range, another useful visibility measurement is the light extinction coefficient, which represents the gradual decrease in light intensity due to absorption and scattering. The light extinction coefficient can be calculated using measured concentrations of the primary contributing species to visibility impairment.[10] At Class I areas, the concentrations of these species are monitored by the Interagency Monitoring of Protected Visual Environments (IMPROVE), which analyzes 24-hour duration samples every 3 days. In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature." This equation is given as follows:

---

[7] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[8] Ibid.

[9] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[10] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

$$
\begin{aligned}
b_{ext} = 2.2 \ & \times f_S(RH) \times [Small\ Sulfate] \\
& + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] \\
& + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Mass] \\
& + 6.1 \times [Large\ Organic\ Mass] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2(ppb)]
\end{aligned}
$$

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[11]

Because the units for the light extinction coefficient (MM^{-1}) are difficult to conceptualize and compare in practical terms, the deciview haze index (dv) was developed. The deciview haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

$$Deciview\ Haze\ Index\ (dv) = 10 \times \ln\left(\frac{b_{ext}\ [Mm^{-1}]}{10\ [Mm^{-1}]}\right)$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated deciview haze index of approximately zero, depending on the site-specific level of Rayleigh scattering.[12]

3.1.2. MATS Processing

The raw CAMx output data most relevant to this regional haze assessment includes an overall average concentration file and a source apportionment concentration file, for each grid utilized (i.e., 12 km and 36 km grids) and for all modeled dates. These raw output files are in Fortran binary and are based on the Urban Airshed Model (UAM) convention. Several post-processor utility programs are used to convert these UAM formatted output files into MATS ready comma separated value (CSV) input files for individual source groups identified by PSAT.

MATS forecasts the level of visibility at Class I areas by using post-processed CAMx modeling output in accordance with monitoring data from the IMPROVE program. The three primary files required to run MATS are

---

[11] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[12] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

the base year model CAMx output, the future year model CAMx output, and the IMPROVE monitoring data. For the purposes of this modeling assessment, 2002 was selected as the base year. The 2018 future year model output refers to each of the CSV files created. The IMPROVE monitoring data is provided as sample data in the MATS software package download from the EPA.

First, MATS uses the IMPROVE monitoring data to identify the 20% best and 20% worst visibility days at each Class I area for the base year, 2002. Using the base year modeled output data on these exact same 20% best and 20% worst days, MATS calculates the average 20% best and 20% worst modeled concentrations of each of the pollutants identified (e.g., sulfates, nitrates, etc.). MATS then performs the same calculations using the same days with the 2018 future year model data. These values are next used to calculate relative response factor (RRF) values, which are ratios of future year modeled concentrations to base year modeled concentrations, both predicted near the same Class I area. The result of this step is a set of best and worst RRF values calculated for all identified species at each Class I area. These RRF values are used in accordance with IMPROVE monitoring data to forecast future deciview haze index values.

The final output from the MATS analysis includes, but is not limited to, the best and worst RRF values calculated for each species and Class I area, the best and worst average daily deciview haze index values for each valid year and Class I area, and the annual average deciview haze index values for each Class I area. In order to perform the required calculations for the PSAT source contribution analysis, all eleven PSAT-negated CSV files were also processed by MATS so that specific PSAT-negated RRF values could be calculated for each PSAT source. These RRF values represent the relative response of each modeled pollutant concentration resulting from the removal of each PSAT source.

3.1.3. PSAT Source Contribution Analysis

The PSAT source contribution analysis determines the individual impact of each PSAT source on visibility at Class I areas. As described in earlier sections, the impacts of the Arkansas BART sources and Entergy's Independence units were traced by the CAMx PSAT tool. The source apportionment CAMx output files were post-processed through MATS to calculate RRF values, which were then used in contribution analysis workbooks provided by the EPA. The calculations in these workbooks are based on the New IMPROVE equation, the IMPROVE monitor data, and the RRF values calculated by MATS.

The contribution analysis workbooks are designed to retrieve the monitored concentrations of visibility impairing pollutants associated with the 20% worst visibility days from 2002 (base year) IMPROVE data, and to multiply them by the 2018 future year RRF values as well as the PSAT-negated RRF values associated with each PSAT source. The resulting values are input to the New IMPROVE equation, which calculates the 2018 projected light extinction values for each of the 20% worst days. These extinction values are averaged and converted into deciview haze index values. PSAT-negated haze index values represent the total 2018 deciview haze index value minus the contribution of the individual PSAT source.

The individual impact of each PSAT source is calculated as the difference between the total 2018 future year haze index value and each PSAT-negated haze index value. For this assessment, the contributions of individual sources located at the same facility were combined in order to compare facility contributions. Figures 3-1 and 3-2 display the uncontrolled baseline scenario facility contributions to deciview haze index for Caney Creek and Upper Buffalo, respectively.

Figure 3-1. Contribution Analysis Results for the Baseline Modeling Scenario at the Caney Creek Wilderness Area

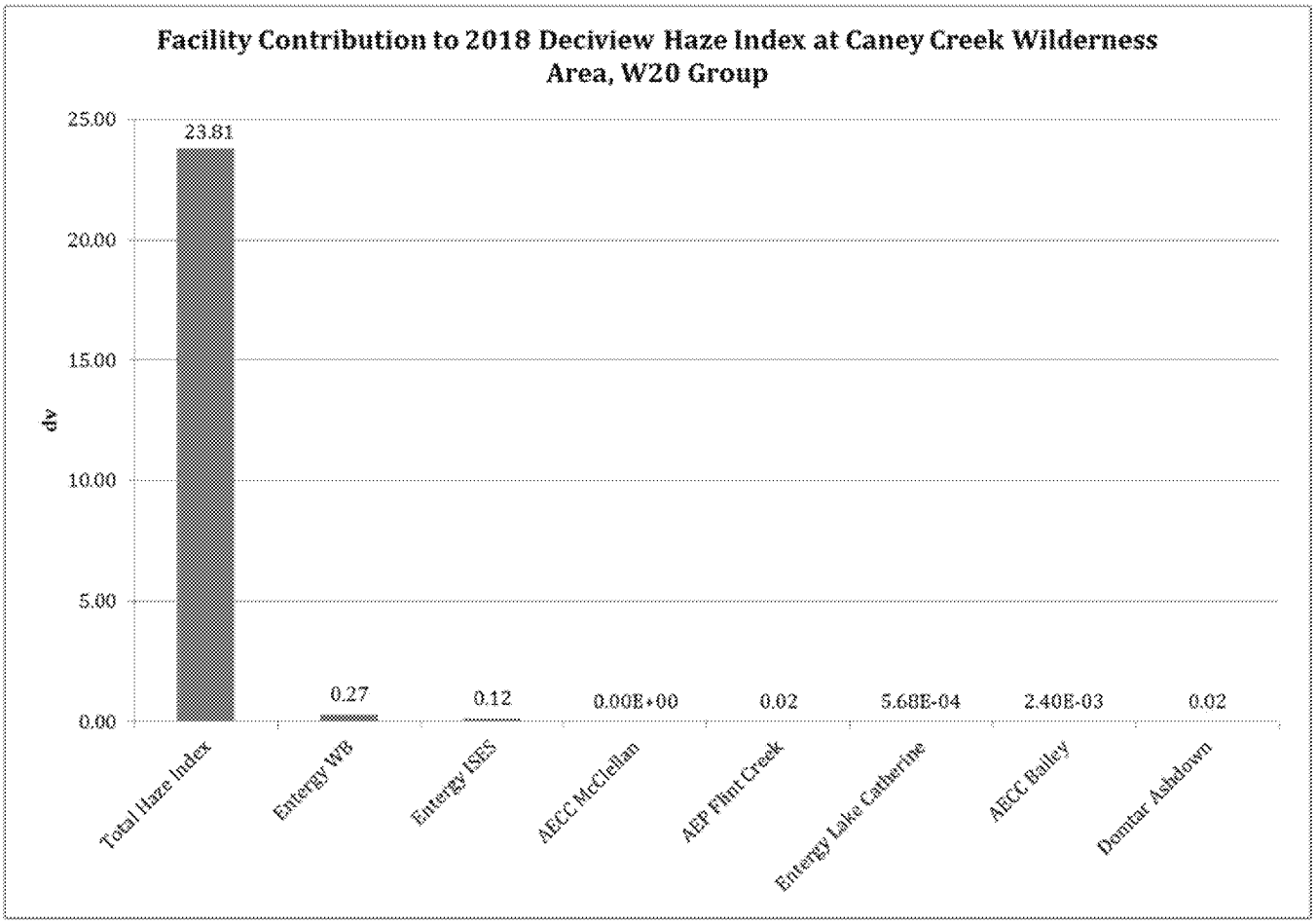
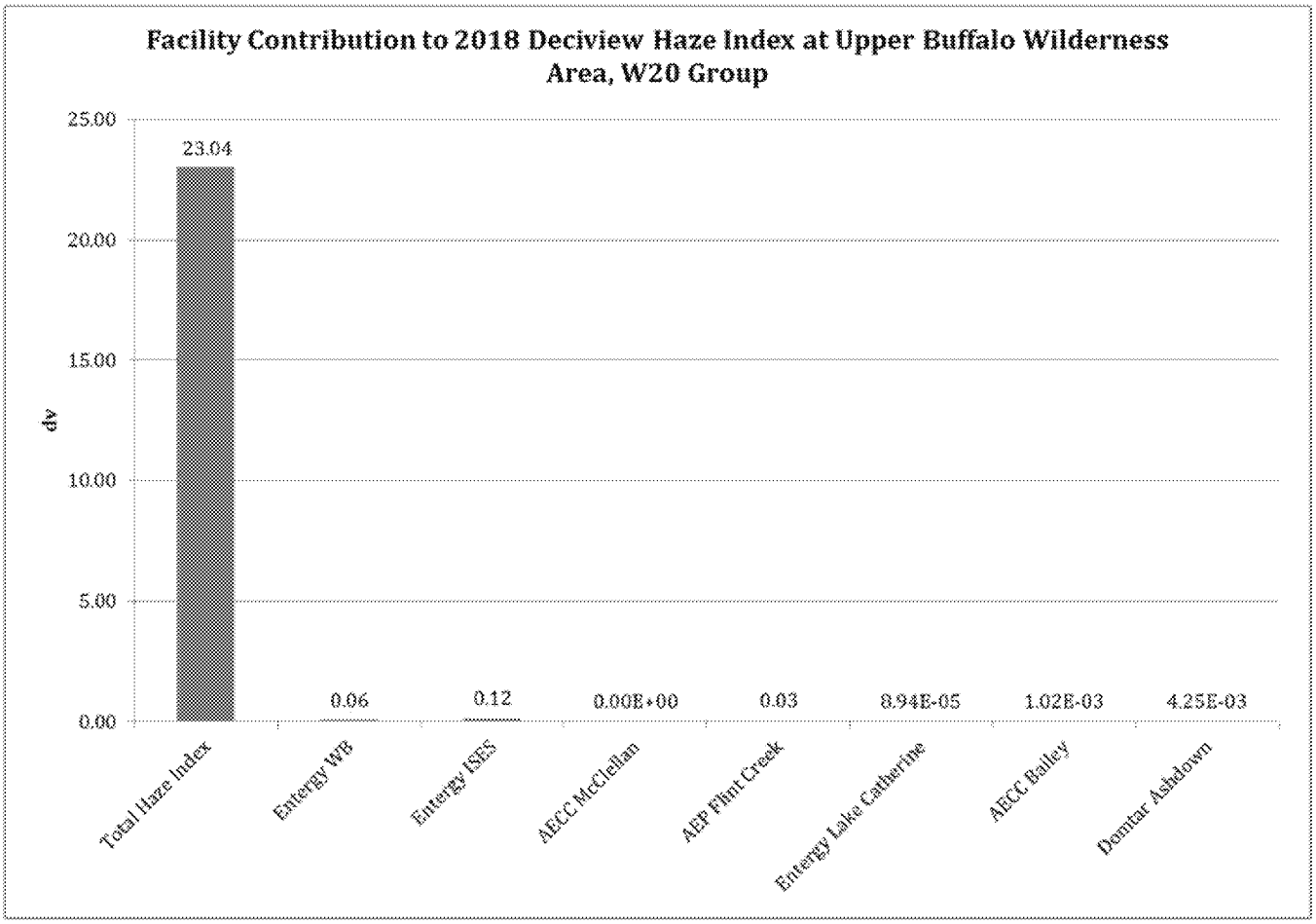


Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area



3.1.4. Uniform Rate of Progress Curve Analysis

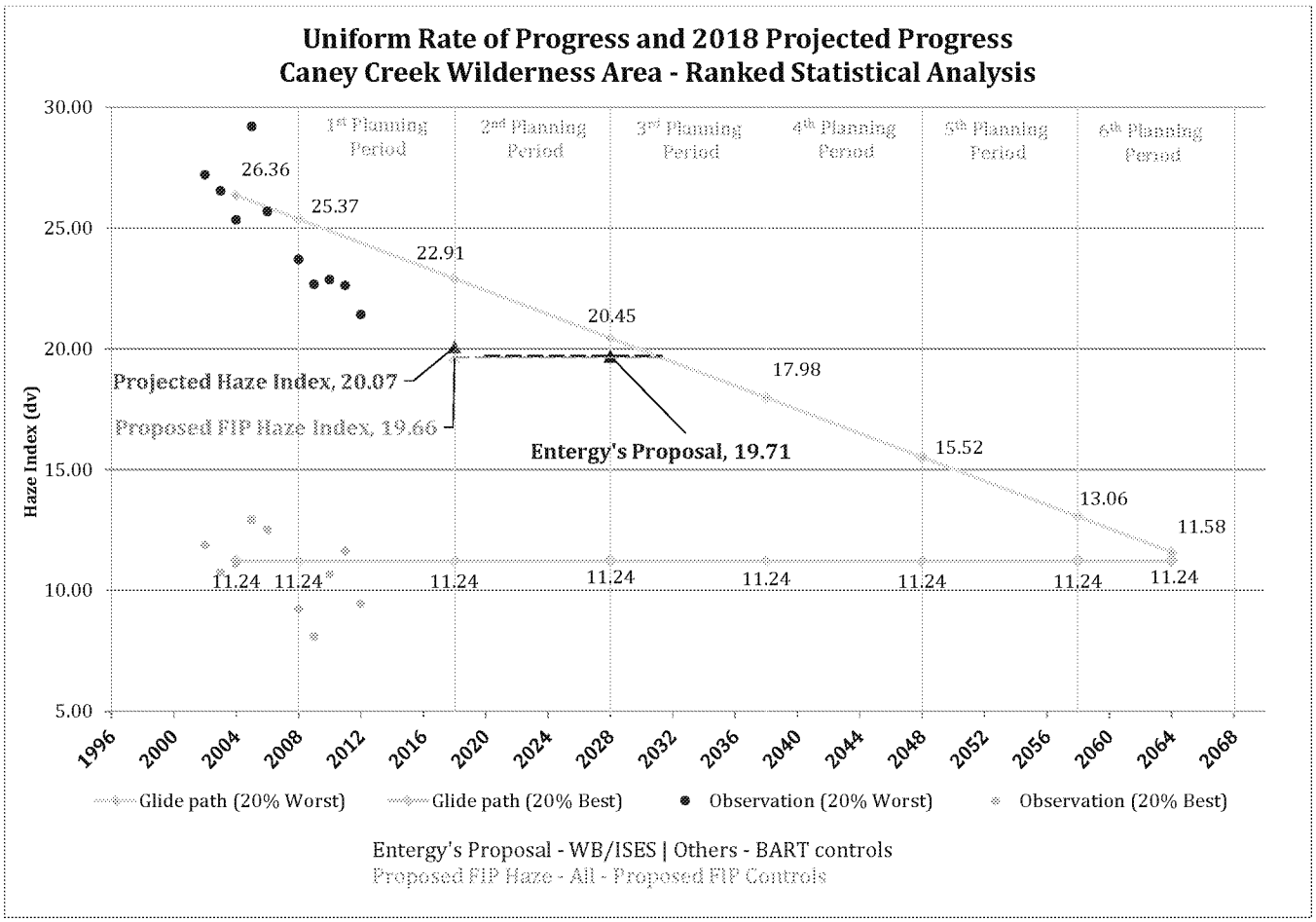
Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIPs "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[13] This requirement is demonstrated by creating a URP graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs are typically initiated in 2004 based on average 2002-2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 initial haze index values are then projected into the future at the minimum rate required to attain natural visibility conditions by 2064. Figures 3-3 and 3-4 display URP curves for Caney Creek and Upper Buffalo, respectively.

Each of these figures display the 20% best and 20% worst URP curves, the average of the 20% best and 20% worst observed deciview haze index values for each year of complete IMPROVE data, and projected haze index values for each modeled scenario. The Projected Haze Index values are obtained from a statistical analysis

[13] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

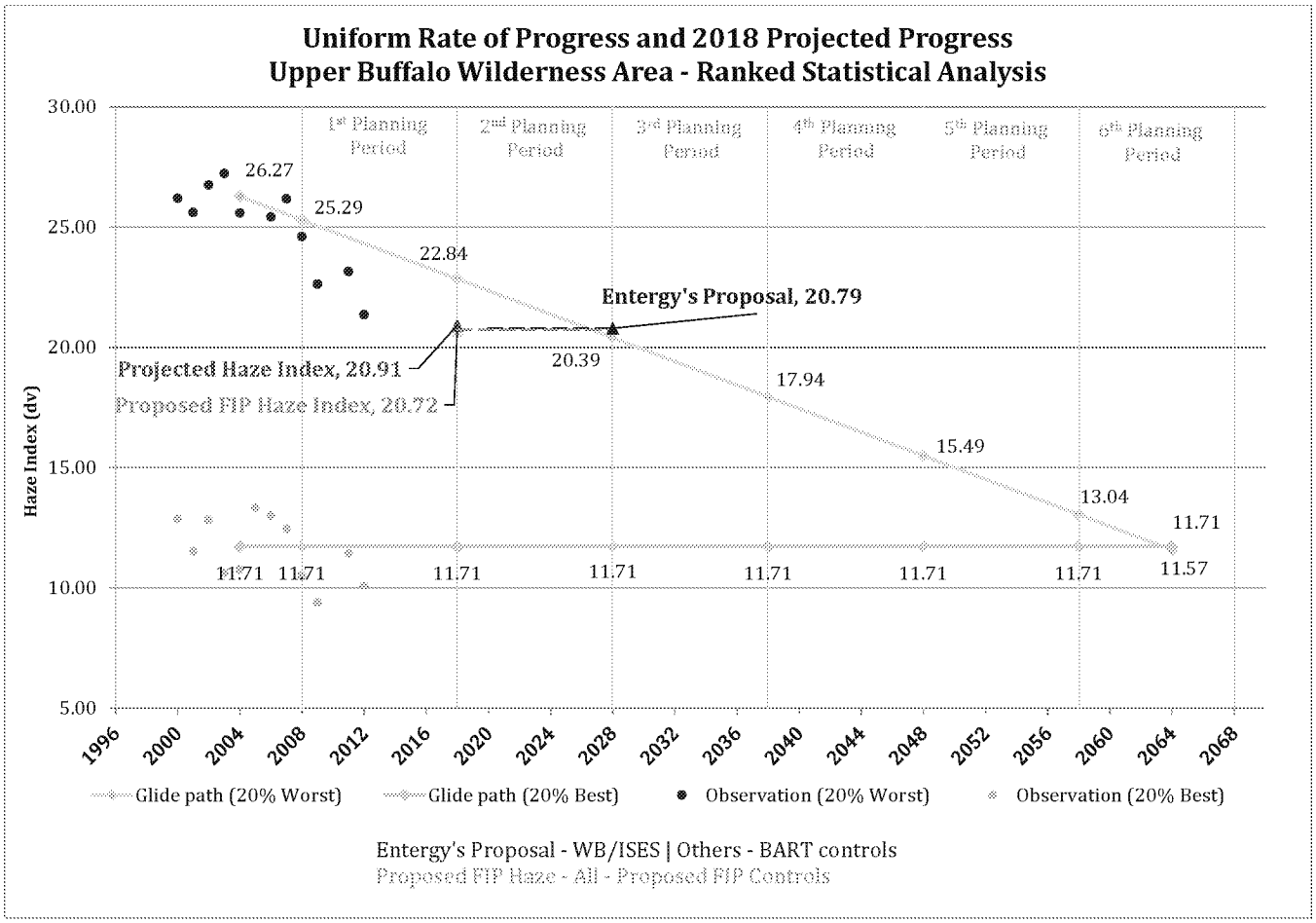
performed using the full set of IMPROVE data for both Caney Creek and Upper Buffalo.[14] The scenario-specific haze index values are calculated by first converting the model-predicted five-year averaged haze index values obtained from MATS into total extinction values in Mm^{-1}. The predicted improvement associated with each scenario is then calculated by finding the difference between the extinction values from the scenario of interest (i.e., Proposed FIP or Entergy's Proposal) and the uncontrolled baseline scenario. The improvement from each scenario is then subtracted from the Projected Haze Index value and converted back into deciviews to obtain scenario-specific haze index values.

Figure 3-3. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Caney Creek Wilderness Area



[14] Trinity Consultants. "IMPROVE Data Statistical Analysis: Discussion and Methodology for IMPROVE Data Statistical Analysis." July 2015.

Figure 3-4. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Upper Buffalo Wilderness Area



APPENDIX A: MODELED EMISSION RATES

Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units

Unit	Uncontrolled Baseline (tpy)		Entergy's Proposal (tpy)		Arkansas FIP (tpy)	
	NO_X	SO_2	NO_X	SO_2	NO_X	SO_2
Independence Unit 1	6,313	14,258	3,150	12,154	3,619	1,357
Independence Unit 2	6,516	15,407	3,347	13,162	3,167	1,521
White Bluff Unit 1	7,580	15,939	--[1]	--[1]	4,145	1,453
White Bluff Unit 2	8,145	16,034	--[1]	--[1]	4,060	1,476
Lake Catherine Unit 4	1,228	3.26	564	3.26	564	3.26

[1] Entergy's Proposal includes the cessation of coal combustion at White Bluff.

IMPROVE DATA STATISTICAL ANALYSIS

Entergy Arkansas Inc.

Entergy

THE POWER OF PEOPLE™

Discussion and Methodology for IMPROVE Data Statistical Analysis

Prepared By:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

July 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit D to EAI Comments

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INTRODUCTION 2-1

3. STATISTICAL ANALYSIS 3-1

3.1. Trend Statistical Analysis **3-1**

3.2. Ranked Statistical Analysis **3-5**

LIST OF FIGURES

Figure 2-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress 2-2

Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress 2-3

Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo 2-4

Figure 3-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis. 3-2

Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis. 3-3

Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data. 3-4

Figure 3-4. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis 3-8

Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis 3-9

LIST OF TABLES

Table 3-1. Chronological Deciview Haze Index Values Observed in January at the Caney Creek Wilderness Area 3-6

Table 3-2. Determination of Monthly and Yearly Data Completeness for the Caney Creek Wilderness Area 3-7

Table 3-3. Ranked Deciview Haze Index Values for the Caney Creek Wilderness Area in January 3-7

1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the proposed Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) which the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) and reasonable progress control requirements. Specifically, the EPA proposed to meet RPGs by presenting options for controlling emissions from the Entergy Arkansas Inc. (Entergy) Independence Plant (ISES), which is not subject to BART.

Trinity Consultants Inc. (Trinity) was tasked with conducting a statistical analysis of observed visibility data gathered through the Interagency Monitoring of Protected Visual Environment (IMPROVE) program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. INTRODUCTION

Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIP "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[2] This requirement is demonstrated by creating a Uniform Rate of Progress (URP) graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs, also known as glide paths, are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs typically were initiated in 2004 based on average 2002 – 2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 values were then projected into the future to intersect with the 20% best days observed value by 2064. To demonstrate attainment with this glide path, the Central Regional Air Planning Association (CENRAP) used the Comprehensive Air Quality Model with Extensions (CAMx) to perform regional haze modeling. The model-predicted haze index values based on the future projected emission rates are used to compare with the glide path proposed value in 2018, the end of the 1st planning period. Figures 2-1 and 2-2 display the uniform rate of progress glide paths for the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo) along with the CENRAP projected haze index.

In addition to the glide paths for the 20% worst days and 20% best days, the URP graphs also present the observed 20% worst and 20% best haze index values from the IMPROVE monitoring observational data for 2002 to 2012. As presented in Figures 2-1 and 2-2 for Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations. This downward trend is consistent with the historical (2002 – 2011) trend in decreasing sulfur dioxide (SO_2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas. Figure 2-3 presents the National Emissions Inventory (NEI) SO_2 emissions from 2002, 2005, 2008, and 2011. Pursuant to the NEI emissions data, the SO_2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO_2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

[2] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

Figure 2-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

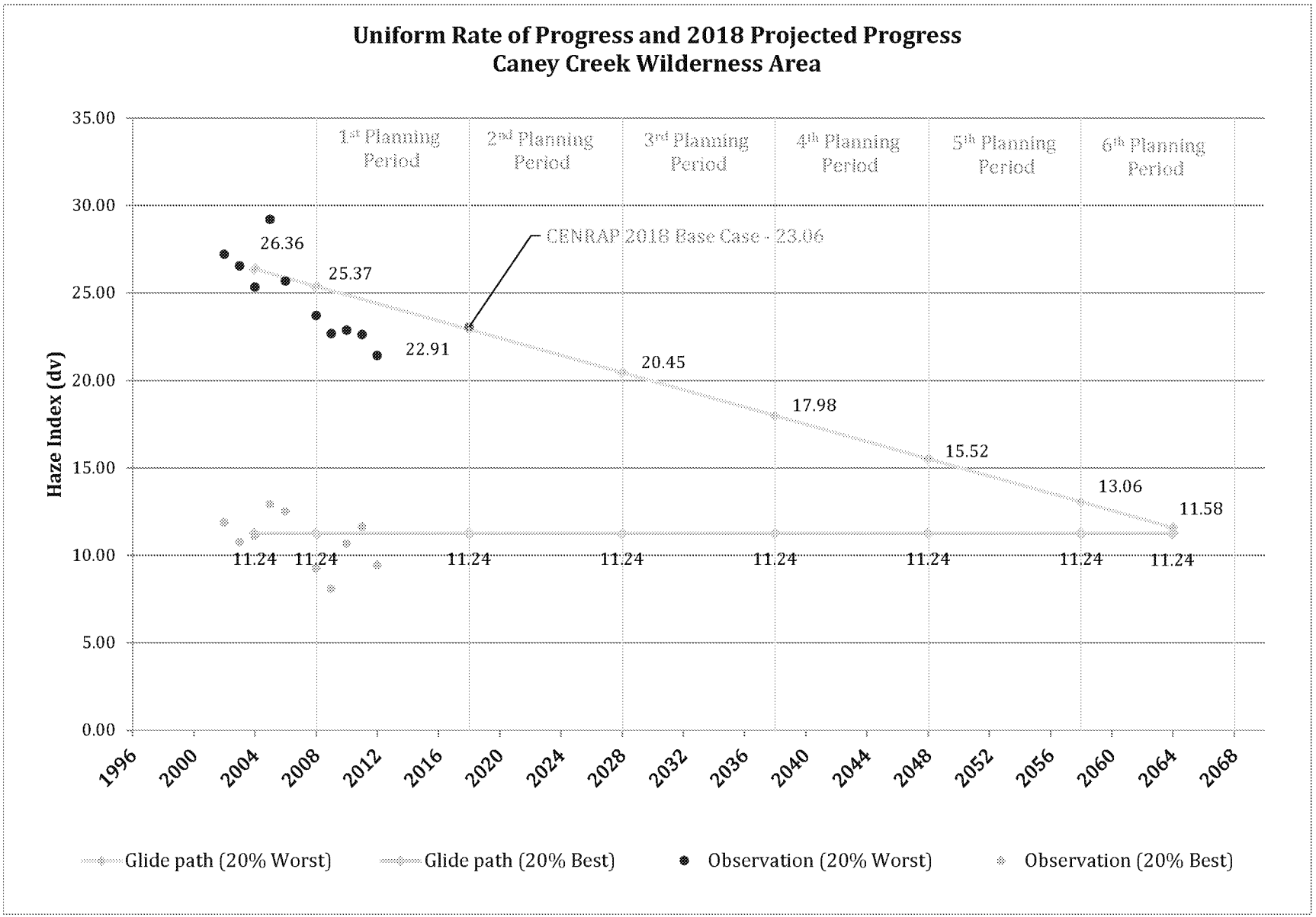


Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

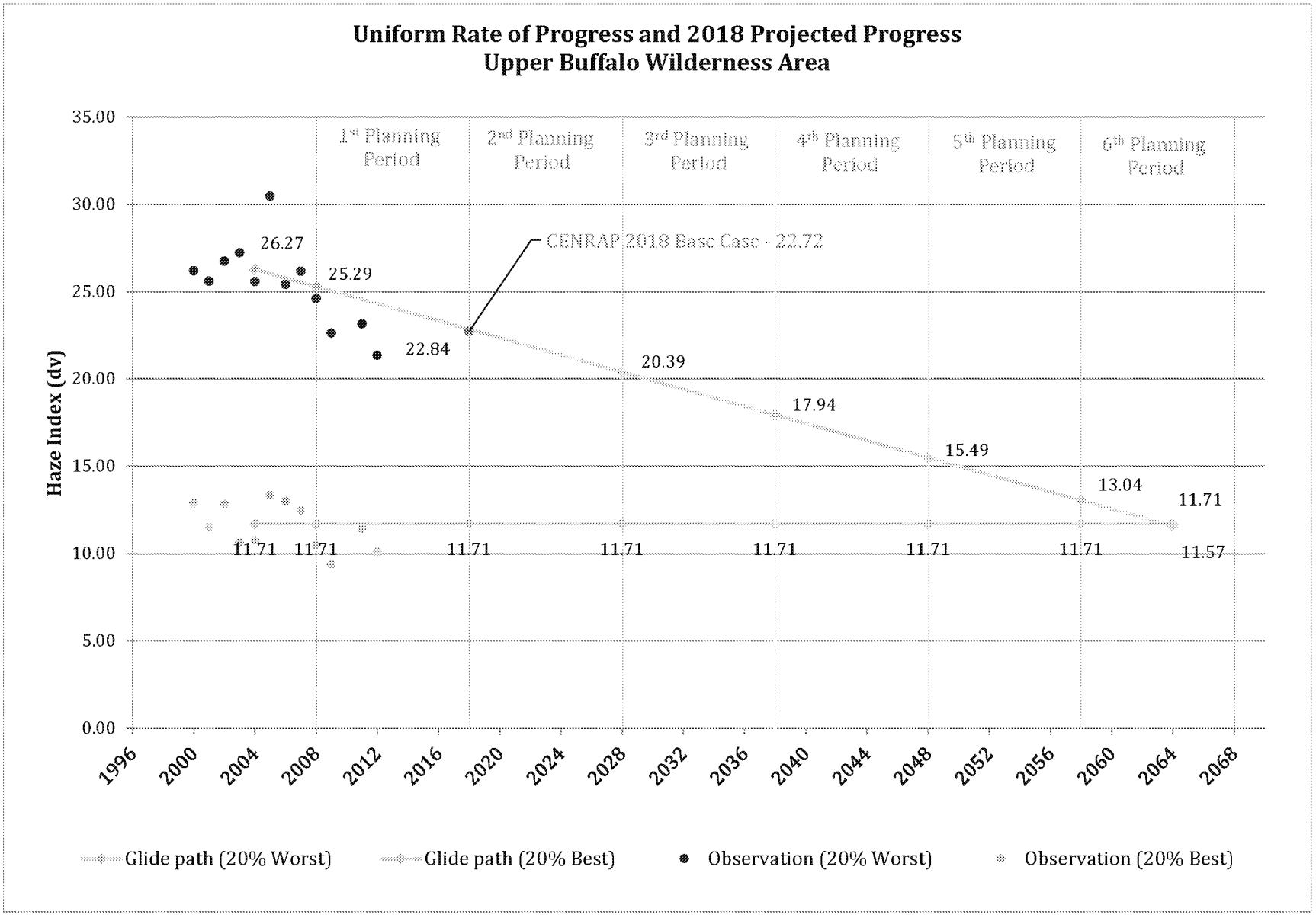
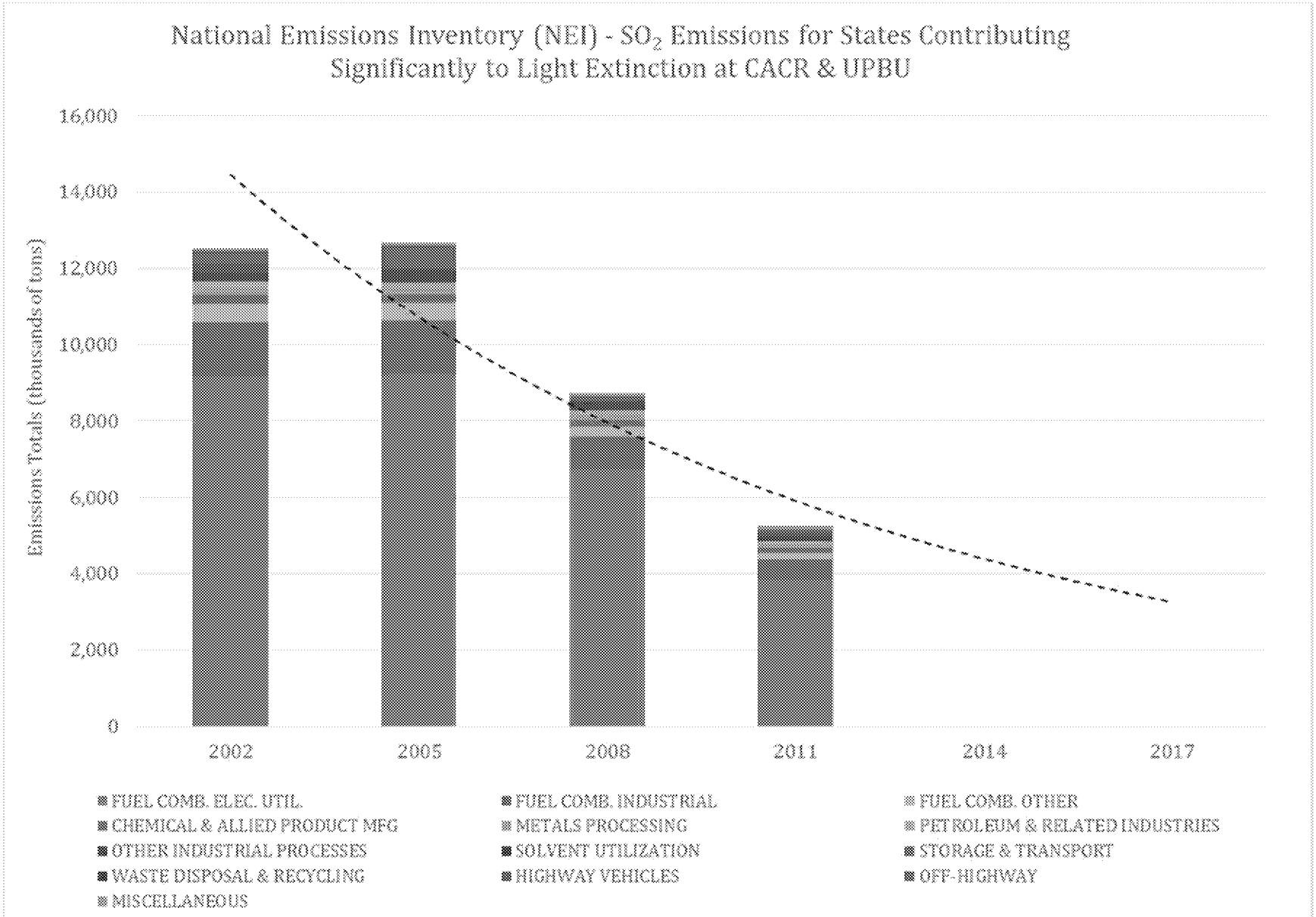


Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo



Based on the above, when looking at the observed values, the CENRAP model predicted regional haze value for 2018 is overly conservative and over predicting the future haze index. Although the predicted 2018 haze index values are good conservative estimates for attainment demonstrations, the values are misleading when assessing the effect of proposed controls on single sources. Additionally, the CENRAP CAMx model predicted haze index does not account for the observed values and the trend predicted if an assessment occurred evaluating the observed values. Therefore, instead of using the CENRAP CAMx predicted 2018 haze index to understand the effect of the control options, a statistically derived projected haze index must be used.

In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data:

- Trend Analysis
- Ranked Statistical Analysis

Each of these analyses are summarized in Section 3 of this report.

3. STATISTICAL ANALYSIS

3.1. TREND STATISTICAL ANALYSIS

A trend analysis using a simple least squares linear regression based on the annual average values was performed. Using this simple "Trend Analysis" methodology, the projected 2018 deciview haze index values of **18.02** dv and **20.44** dv were determined for Caney Creek and Upper Buffalo, respectively. Figures 3-1 and 3-2 present the uniform rate of progress glide paths for Caney Creek and Upper Buffalo when the 2018 projected haze index is based on the statistical trend of the observed data. These values are estimated without consideration of additional controls added as a result of the proposed FIP. Presented alongside these projected values are the estimated values that would result from adopting the proposed FIP controls (Proposed FIP Haze Index) as well as the controls proposed by Entergy (Entergy's proposal). Entergy's proposal includes meeting more stringent SO_2 emission rates at ISES and Entergy's White Bluff plant (WB) by 2018, the installation of low nitrogen oxides (NO_X) burners at ISES and WB, and the cessation of coal combustion at the WB plant by 2028.

This statistical analysis is not, however, a realistic model for expected visibility improvement since this trend is based on a limited set of data—the 20% worst deciview haze index values for each year—which may not be representative of the complete set of IMPROVE data. Therefore, a more extensive statistical analysis was performed to predict future deciview haze index values based on the full set of IMPROVE observation data.

A review of the IMPROVE data sets for both Caney Creek and Upper Buffalo indicate that there is no convincing correlation between the observed deciview haze index value and the date of observation. That is, there is no detectable temporal trend in the IMRPOVE data. However, as shown in Figure 3-3, the maximum, third quartile, median, first quartile, and minimum data points do indicate a consistent downward trend from year to year, which suggests that over time, from year to year and month to month, the first highest, second highest, third highest, etc. observed values will follow a trend which can be used to predict future values.

IMPROVE data obtained for both Caney Creek and Upper Buffalo spanned the years 2000 to 2012 where data is taken every three days. However, both IMPROVE data sets contain regions of time for which data is not available. Because some years have less data points than other years, it is therefore impossible to predict future deciview haze index values using the nth largest value without introducing unnecessary biased skew. For example, the Caney Creek IMPROVE data for 2000 includes only 52 values while 2004 contains 122 values. Therefore, the 52nd highest value (also the minimum value) for 2000 is 4.04 dv while the 52nd highest value for 2004 is 20.00 dv. Since it would be inappropriate to compare the minimum value of 2000 with a value closer to the median of 2004, further refinement to the methodology is required.

One option is to simply remove years with data not meeting a defined criteria for completeness. This option, however, is not preferred because it discounts a large quantity of valuable data. Additionally, this option only slightly reduces the potential for skew described above. The final chosen methodology (Ranked Statistical Analysis) addresses both of these issues by minimizing the skew due to incomplete data while maximizing the usage of available data.

Figure 3-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

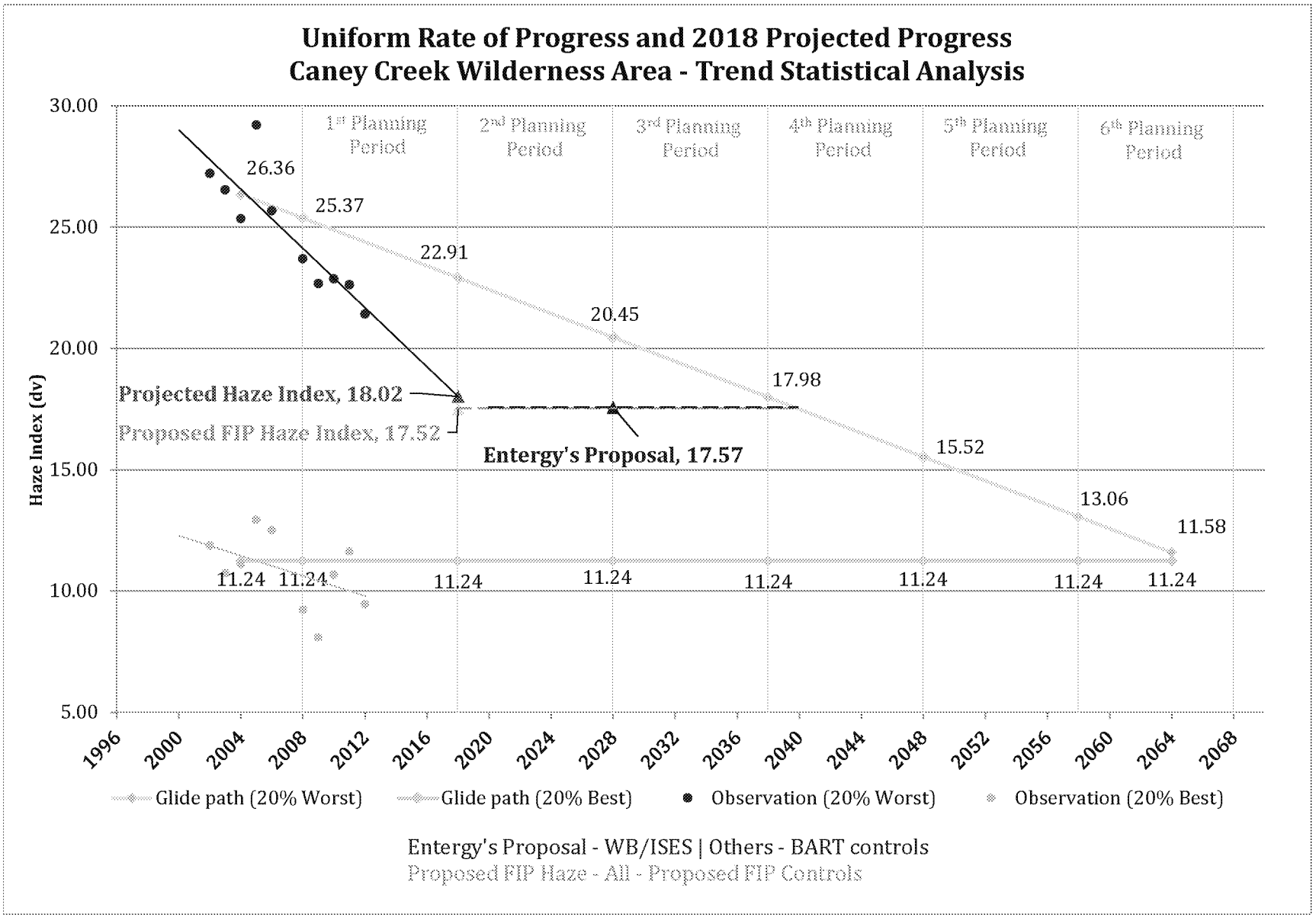


Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

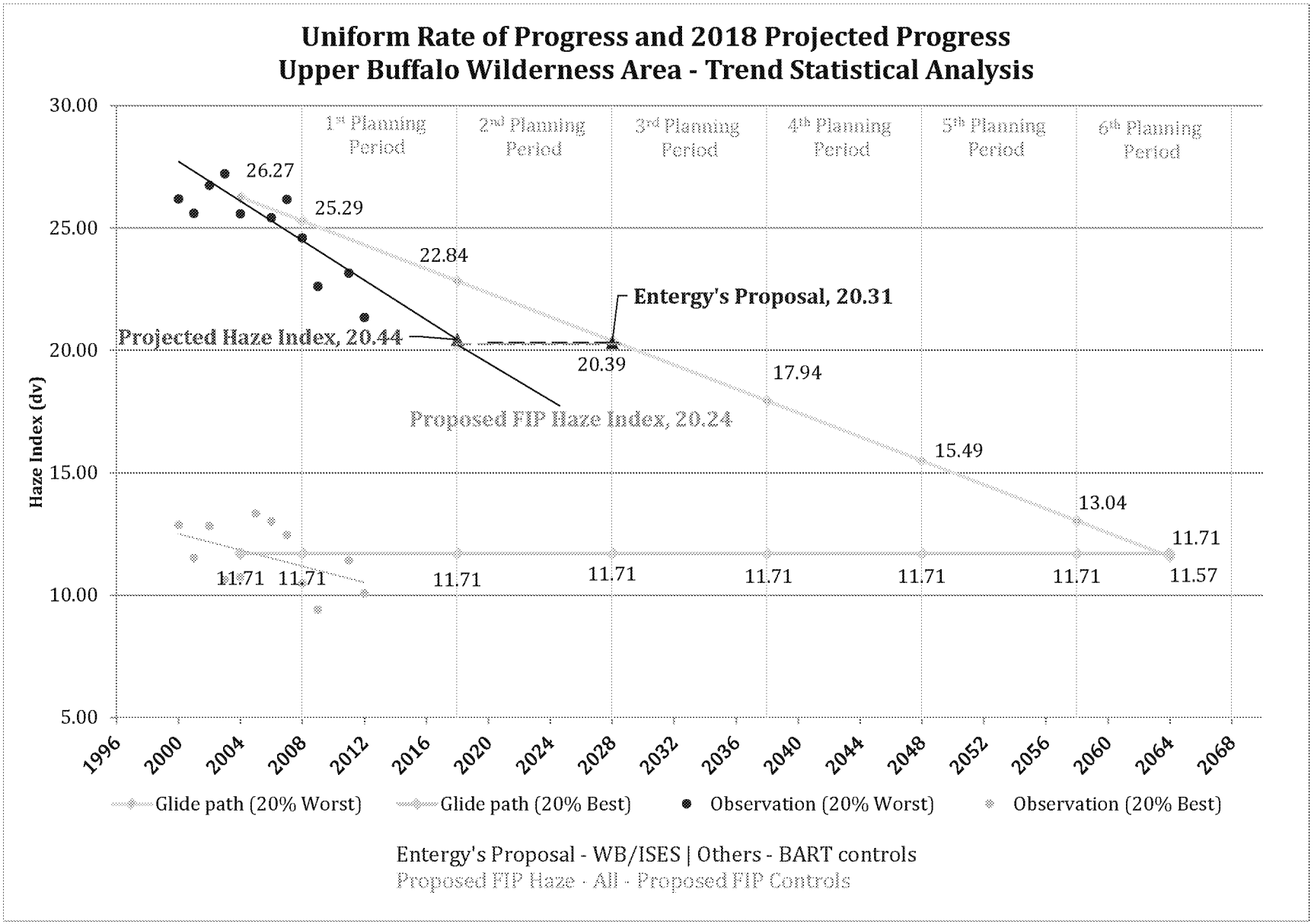
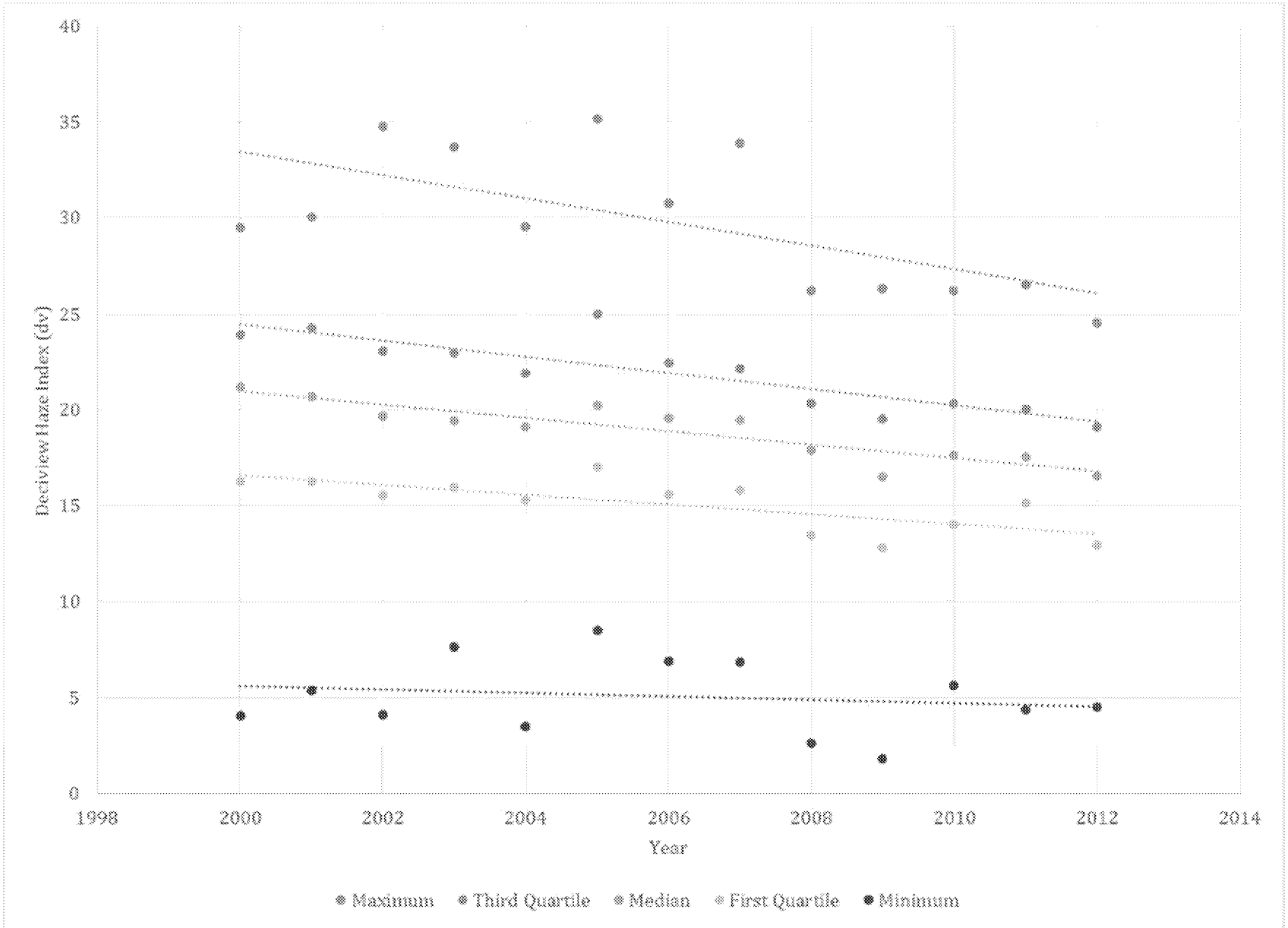


Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data.



3.2. RANKED STATISTICAL ANALYSIS

The chosen methodology, described as Ranked Statistical Analysis, begins with the chronological organization of the IMPROVE data from every year, as displayed in Table 3-1 as an example. It was determined that a month of data is incomplete for a year if less than nine (9) days of data points are available (eight days for February) for that month. This completion criteria corresponds to approximately overall 90% completeness. Table 3-2 presents the resulting completeness determinations of each month and year for Caney Creek. If a given month has less than nine out of thirteen years of complete data, that month is discounted from the calculations and is not considered in the future projections. As shown in Table 3-2, April only had eight years of complete data for Caney Creek; therefore, April was not considered in the projections. Once the completeness determination was completed, the haze index values for each complete month and year were then ranked so that the values for each month from year to year were aligned in descending order. Table 3-3 presents the ranked observations for Caney Creek for the complete years of January data as an example. These ranked monthly values were used to predict the daily haze index values for each month of the year 2018. Using this set of predicted 2018 values, the 2018 average of the 20% worst days for visibility was calculated to be **20.07** dv for Caney Creek and **20.91** dv for Upper Buffalo. Figures 3-4 and 3-5 display these predicted 2018 values in relation to the URP curves for each Class I Area. Also displayed are the estimated proposed FIP haze index and the haze index based on Entergy's proposed controls.

The haze index values predicted using the Ranked Statistical Analysis are consistent with the downward trend from the observed values and are more conservative than the Trend Analysis. The Trend Analysis relies on the sampling data generated from average worst 20% days IMPROVE data and therefore, the sampling data is limited to only one (1) value per year. This limited size of sampling can induce some bias in the statistical analysis. However, the statistical samples in the Ranked Statistical Analysis, unlike the Trend Analysis, includes at least nine (9) values per month or a minimum of 108 data points for each complete year. The sample data used for the Ranked Trend Analysis included at least 8 complete years or a minimum of 860 data points. The use of this large data sample in the Ranked Statistical Analysis makes this analysis more robust and un-biased in predicting the projected trends. The use of a larger sample point ranked on a monthly basis also preserves the temporal and diurnal patterns in the observed data. By predicting monthly future values, these diurnal and temporal pattern are sustained in the statistical analysis and therefore, reduce the bias due to missing values.

Based on statistical analysis completed, the Ranked Statistical Analysis is more appropriate for determining the downward trend in the haze index based on IMPROVE observed data. When comparing the ranked versus trend analyses, the trend analysis would suggest the programs external to the Regional Haze rule will have a more profound effect on the glide path which will approach the natural background in 2028 and 2042 for Caney Creek and Upper Buffalo, respectively. When looking at the more conservative Ranked Statistical Analysis, the URP will be approached after 2038/2044 for Caney Creek and Upper Buffalo, respectively, but well before the 2064 deadline. Under either approach, analysis of the data trends show that the rate of visibility improvement is outpacing the URP graphs at both Caney Creek and Upper Buffalo.

Table 3-1. Chronological Deciview Haze Index Values Observed in January at the Caney Creek Wilderness Area

Julian Day	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	--	--	--	--	14.59	--	--	--	10.24	18.60	--	--	11.70
2	--	--	21.27	--	--	--	--	--	--	--	20.47	--	--
3	--	--	--	19.27	--	--	--	18.54	--	--	--	14.72	--
4	--	--	--	--	13.18	11.69	--	--	--	22.85	--	--	14.80
5	--	--	17.81	--	--	--	6.88	--	--	--	17.32	--	--
6	--	--	--	20.09	--	--	--	23.10	--	--	--	12.71	--
7	--	--	--	--	15.61	10.71	--	--	--	10.80	--	--	18.88
8	--	--	18.18	--	--	--	13.96	--	--	--	14.95	--	--
9	--	--	--	20.33	--	--	--	6.86	--	--	--	12.89	--
10	--	--	--	--	29.56	14.03	--	--	--	26.11	--	--	12.66
11	--	--	14.41	--	--	--	13.61	--	--	--	18.43	--	--
12	--	--	--	15.61	--	--	--	13.10	--	--	--	20.13	--
13	--	--	--	--	26.26	17.13	--	--	--	15.40	--	--	6.80
14	--	--	10.42	--	--	--	7.68	--	--	--	19.31	--	--
15	--	--	--	27.57	--	--	--	--	--	--	--	25.25	--
16	--	--	--	--	19.61	24.99	--	--	--	14.47	--	--	14.97
17	--	--	21.57	--	--	--	17.86	--	--	--	18.75	--	--
18	--	--	--	15.35	--	--	--	--	--	--	--	19.63	--
19	--	22.79	--	--	19.40	--	--	--	--	19.58	--	--	--
20	--	--	--	--	--	--	18.74	--	--	--	18.14	--	--
21	--	--	--	21.74	--	--	--	--	--	--	--	12.33	--
22	--	21.70	--	--	24.23	20.17	--	--	--	21.15	--	--	18.07
23	--	--	15.85	--	--	--	13.47	--	--	--	13.43	--	--
24	--	--	--	17.45	--	--	--	16.37	--	--	--	21.59	--
25	--	--	--	--	11.67	21.57	--	--	15.07	21.52	--	--	4.52
26	--	--	14.01	--	--	--	9.72	--	--	--	7.38	--	--
27	--	--	--	25.98	--	--	--	19.94	--	--	--	17.15	--
28	--	22.76	--	--	14.65	19.52	--	--	18.43	20.24	--	--	10.71
29	--	--	20.39	--	--	--	12.82	--	--	--	11.21	--	--
30	--	--	--	17.81	--	--	--	15.78	--	--	--	20.67	--
31	--	13.34	--	--	19.07	17.61	--	--	10.74	8.28	--	--	19.91

Table 3-2. Determination of Monthly and Yearly Data Completeness for the Caney Creek Wilderness Area

Month	Total Number Days	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Number of Complete Years
January	31	No	No	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	9
February	28	No	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	9
March	31	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	11
April	30	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	8
May	31	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	12
June	30	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	11
July	31	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	10
August	32	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	9
September	30	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	11
October	30	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	10
November	30	Yes	No	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	Yes	Yes	9
December	31	No	No	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	9

Table 3-3. Ranked Deciview Haze Index Values for the Caney Creek Wilderness Area in January

	2002	2003	2004	2005	2006	2009	2010	2011	2012	Number of Days with Data
1	21.57	27.57	29.56	24.99	18.74	26.11	20.47	25.25	18.88	9
2	21.27	25.98	26.26	21.57	17.86	22.85	19.31	21.59	18.07	9
3	20.39	21.74	24.23	20.17	13.96	21.52	18.75	20.13	14.97	9
4	18.18	20.33	19.61	19.52	13.61	21.15	18.43	19.63	14.80	9
5	17.81	20.09	19.40	17.61	13.47	19.58	18.14	17.15	12.66	9
6	15.85	19.27	15.61	17.13	12.82	18.60	17.32	14.72	11.70	9
7	14.41	17.45	14.59	14.03	9.72	15.40	14.95	12.89	10.71	9
8	14.01	15.61	13.18	11.69	7.68	14.47	13.43	12.71	6.80	9
9	10.42	15.35	11.67	10.71	6.88	10.80	7.38	12.33	4.52	9
10	--	--	--	--	--	--	--	--	--	0
11	--	--	--	--	--	--	--	--	--	0

Figure 3-4. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis

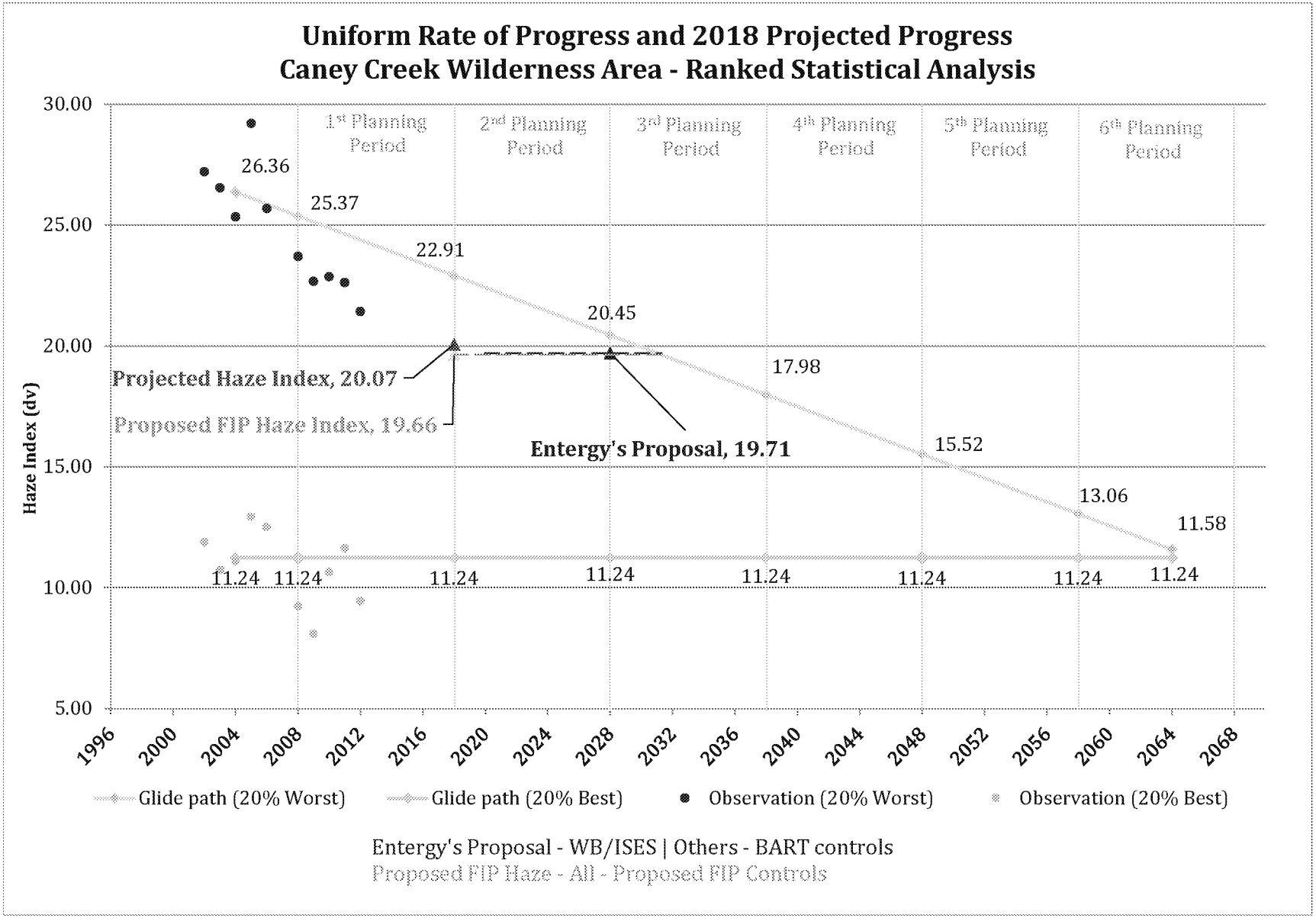
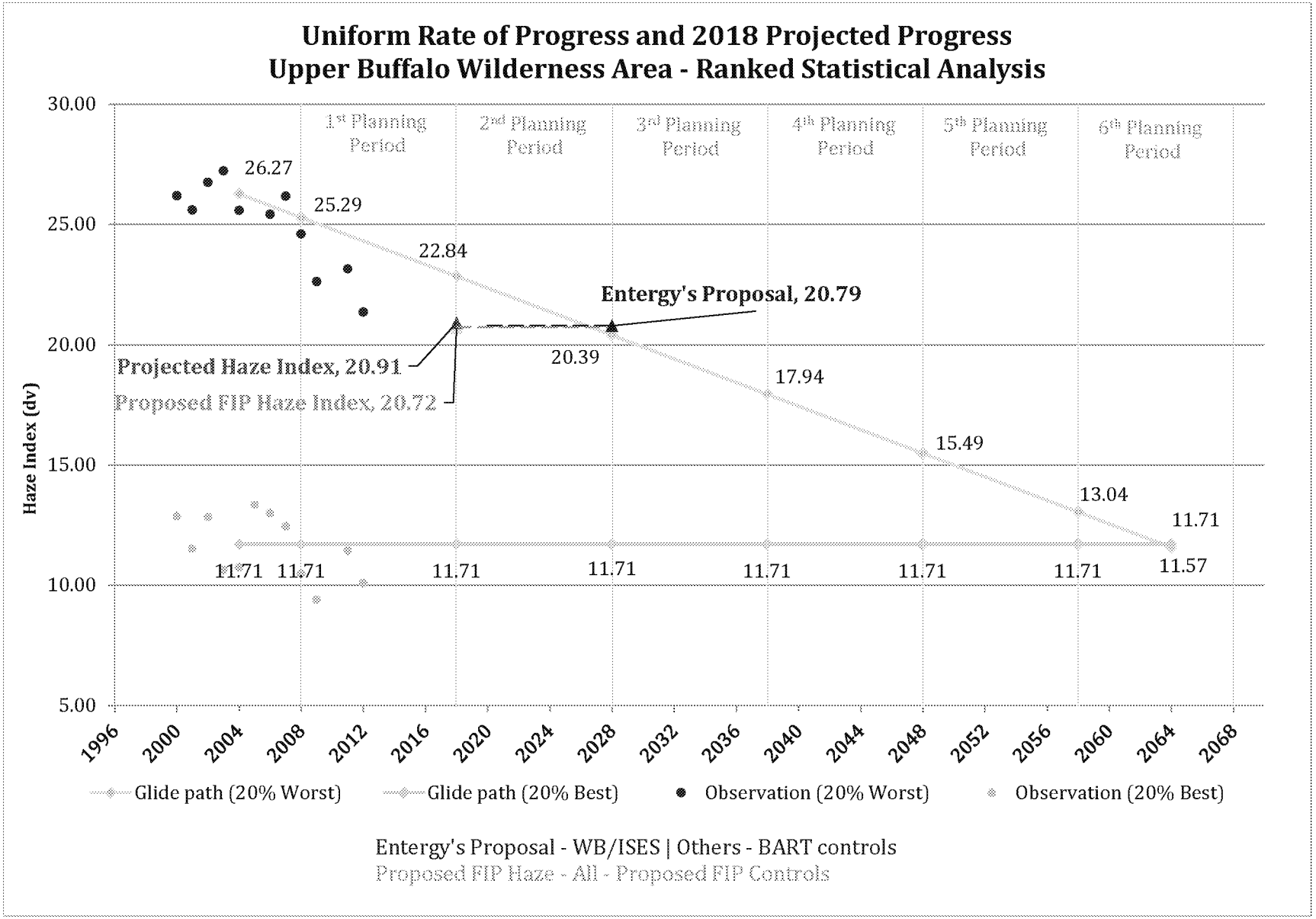


Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis



TECHNICAL PAPER

ISSN 1047-3289 *J. Air & Waste Manage. Assoc.* 52:1238-1243
Copyright 2002 Air & Waste Management Association

Just-Noticeable Differences in Atmospheric Haze

Ronald C. Henry
Department of Civil and Environmental Engineering, University of Southern California, Los Angeles

ABSTRACT

This article examines the only available experimental data taken in the natural environment on the ability of an observer to perceive small, incremental changes in the colorfulness of objects seen through atmospheric haze and estimates an appropriate just-noticeable difference (JND) from these data. This experimentally determined threshold of perception is compared to changes in the deciview scale. Based on these experimental results, the deciview scale is found to not be uniform over a wide range of visibility conditions, as has been previously claimed. In addition, a 1-deciview change never produces a perceptible change in haze, as defined by a 95% probability of producing a measurable change in the colorfulness of an object seen through the haze.

INTRODUCTION

Section 169A of the Clean Air Act sets a national goal of protecting visibility in national parks and other pristine areas. Under regulations promulgated in 1980, the U.S. Environmental Protection Agency (EPA) has taken specific regulatory action to protect visibility in the Grand Canyon National Park by reducing emissions of sulfur dioxide from the Navajo Electric Generating Station near the eastern end of the Grand Canyon and from the Mohave Power Plant at the western end. However, current concerns about visibility degradation stem from regional haze that is difficult or impossible to attribute to individual sources of air pollution. This issue is addressed by regional haze regulations that set a goal of making reasonable progress toward improving regional visibility in five-year increments, leading to the attainment of "natural conditions" by 2064.[1] Progress is to be measured by an innovative visibility metric for regulatory purposes known as the deciview,[2] used instead of visual range or other visibility metrics because it "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions."[1] One goal of this article is to assess this and other claims about the deciview scale in light of actual measurements of the perception of haziness. Since the deciview scale is meant to quantify small, just-noticeable differences (JNDs) in visibility, a review of the basic concepts of thresholds and JNDs is given.

IMPLICATIONS

Current regulations use the deciview to quantify a perceptible change in regional haze. Based on the results of this article, changes in atmospheric extinction required to meet regional haze regulations calculated using deciviews would probably be too small, sometimes much too small. In addition, these regulations require that progress be assessed over five-year intervals. In this way, the burden of reducing emissions is spread evenly over many years. However, since deciviews are not uniform in perception, it may be that the actual improvement in visibility will not be uniform.

Perceptual Threshold Concepts

For all the senses, thresholds are necessary—otherwise we would be constantly distracted by small, inconsequential changes in the environment. A background of random noise, some from the environment and some produced inside our own sensory organs, would make it next to impossible to form a stable view of the world. Our vision would be like the grainy, speckled images produced by night vision cameras. On a more basic scientific level, the study of thresholds of the senses has led to a deeper understanding of sensory physiology and how our vision and other senses function. For this reason, virtually all studies of thresholds of vision have been carried out under controlled laboratory conditions.

Since laboratory conditions seldom mimic the natural environment, thresholds so determined are generally not useful in predicting perception in the complex natural world. As an example of the drastic effect that experimental conditions can have on perception, consider an experiment to determine the ability of an observer to perceive the difference in the length of two strings—or to put it another way, to determine the threshold for perception of the difference in the length of two strings, or the JND. If the two strings are widely separated when presented to the observer, the threshold will be much greater than if the two strings are presented side by side. The visual equivalent of this is the use of a split image to determine the ability to distinguish color. If two colors are seen as two halves of a disk, the JND is very small, but if one

EPA-HQ-2018-002296

color is presented as a full disk, followed a few seconds later by the other color, the JND will be much larger. The topic of the background on which the colors are seen is also important (e.g., if it is black or a complex scene). In general, many conditions influence thresholds; for this reason, the results of laboratory experiments should be applied with great caution to the natural environment. Thus, this article will report and analyze data taken in a unique experiment in the natural environment with a goal of determining a JND in atmospheric haze.

In the above discussion, the terms "threshold" and "JND" have been freely used, but not defined. The naïve definition of a threshold or JND is clear: It is the smallest amount, or change in, a physical stimulus that is detectable. Ideally, a 1-JND change in a stimulus such as contrast or color would always result in the observer seeing a change, and anything less would not. Of course, the senses do not work in this simple on-off manner. In actuality, as the change in the physical stimulus increases, the probability that the observer will detect the change increases as well. Thus, thresholds and JNDs have always been defined by a probability of detection. Furthermore, the sensitivity of people's senses varies from person to person and during a person's life. Even if each person had a single, idealized threshold, the response of the general population would be best described by a probability of detection.

Repeated matching by the method of adjustments is one of the oldest methods of determining a JND. Falmagne[3] described this and other methods to quantify perception. Briefly, the observer is shown a target color and a variable test color and is asked to adjust the test color until it matches the target. Taking random starting points, the matching procedure is repeated as often as is practical. Since the observer has judged the matching color to be the same as the target color, the variability in the matches is a measure of a JND around the target. The standard deviation of the matches is one measure of this variability that is often used; another is the difference between the 75th and the 25th percentile of the match distribution. The method of adjustments has been replaced in laboratory studies by methods that give less control to the observer and more to the researcher and therefore improve the reproducibility of the results (unfortunately, these methods are impractical for field studies). However, JNDs are still defined by some measure related to the probability of detection. The final determination of the value of a JND or threshold is really dependent on how the measurements are made and how the data are interpreted. For the experimental data used in this article, the method of adjustments was used and a JND related to the standard deviation of repeated matches was defined.

Atmospheric Visibility Concepts

In the classical theory of atmospheric visibility, the threshold of contrast perception, that is, the threshold for perception of a large, dark object on the horizon, is assumed to be 2%.[4] This number is somewhat arbitrary. The Federal Aviation Administration (FAA) has taken the more conservative value of 5.5% as a contrast threshold for the definition of visual range, presumably because approaching aircraft seen from a cockpit are usually neither large nor dark. The common formula for visual range, using the 2% threshold, is

$$V_R = \frac{-\ln(0.02)}{b_{ext}} = \frac{3.9}{b_{ext}} \qquad (1)$$

where b_{ext} is the extinction coefficient of the atmosphere, which is assumed to be homogeneous. The extinction coefficient in the denominator of the formula can be thought of as the fraction of light that is lost as it traverses 1 m of air. For completely clear air, b_{ext} has a value of about 10×10^{-6} m^{-1} or 10 Mm^{-1}, or a visual range of about 390 km. More typically, particles in the air usually increase the extinction coefficient to 150–300 Mm^{-1} or more. Typical visual ranges are about 10 km in the eastern United States and 50 km or more in the western United States. Closely related to b_{ext} and visual range is the more general concept of optical depth. For a target at a distance x, this is defined as xb_{ext}. It is dimensionless; if b_{ext} is held constant it represents distance, and if the distance is constant, it represents changes in b_{ext}. From eq 1, the visual range corresponds to an optical depth of 3.9, and a distance of about one quarter of the visual range is equivalent to an optical depth of 1.

Despite lacking a firm psychophysical or experimental basis, the visual range defined by the 2% threshold has stood the test of time. However, while visual range has proven to be a good surrogate for atmospheric visibility for the aviation community, it is of limited value in addressing the concerns of the air quality community. Unlike aviation, where poor visibility is of greatest interest, the air quality community is primarily concerned with relatively small changes in good visibility. Pitchford and Malm[2] have proposed the deciview as a visibility indicator more suited to air quality regulations. If the extinction coefficient is given in Mm^{-1}, then deciview is defined as

$$v = 10\ln(b_{ext}/10) \qquad (2)$$

Current regional haze visibility regulations state that:

(1) A 1-deciview change in haziness is a small, but noticeable, change in haziness under most circumstances when viewing scenes in Class I areas.
(2) Deciview units are uniform in perception over a wide range of visibility conditions; that is, a 1-deciview change is just perceptible regardless of the visibility conditions.[1]

Exhibit E to EAI Comments

ED_002110_00032342-00217

EPA-HQ-2018-002296

The next section describes a color matching experiment in the Great Smoky Mountains National Park. The results of this experiment are used to estimate a just-noticeable change in haze based on color perception. The validity of the claims for deciviews will be evaluated by comparison to experimental estimates of JNDs.

EXPERIMENTAL DATA

During summer 1995, a group of researchers from universities, government agencies, and private companies conducted the SouthEast Aerosol and Visibility Study (SEAVS) in the Great Smoky Mountains National Park. The SEAVS focused largely on aerosol composition,[5,6] airborne particle size distribution,[7,8] and the role of water in the aerosol.[9-11] However, the SEAVS had a number of other aspects, including a study of the perception of color through atmospheric haze.[12] The methods and primary results of the color perception study are described below.

The perceived colors of natural targets were quantified by color matching using a specially constructed visual colorimeter.[13] An observer looked at some scene element, such as a barn or green field, with one eye. The observer looked with the other eye in the visual colorimeter at a color spot, which the observer adjusted to match the color of the target. The perceived color was recorded as the amount of red, green, and blue light in the color match. At the same time, the spectrum of the light coming from the target was measured by a telespectroradiometer. A color appearance model was applied to produce measures of the perceived color as recorded by the visual colorimeter and as calculated from the spectrum.[14]

Of most interest here are the hue and colorfulness. The hue is what most people call the color—red, green, blue, yellow, and so on. It is quantified as a mixture of pure red, green, blue, or yellow lights. The colorfulness is the degree to which the hue is expressed; it is similar to the concept of saturation. A deep red color would have a colorfulness of about 100, while a colorfulness of 10 or less is almost achromatic (i.e., white or gray).

Two observers (Mahadev and Urquito) made color matches of a set of natural targets during the SEAVS. These observers were both males in their 20s with normal color vision. Each had received extensive training in color matching using the visual colorimeter. The scattering coefficient of the atmosphere was measured by a nearby nephelometer; particle absorption was small and its contribution to the extinction coefficient ignored. The full details of the experiment are found in Mahadev.[15]

The perception study found that viewing through a semitransparent atmosphere affected the perception of hue and colorfulness in a highly nonlinear way. The eye appeared to split the light coming from the target into two parts, the haze and the target. The result was that as the haze increased, the hue of the target as seen by the observer remained constant. However, because the increasing haze scattered more light into the sight path, the hue calculated from the spectrum became bluer. To the observer, the main effect of haze was to decrease the perceived colorfulness. Furthermore, the decrease in colorfulness seemed to be exponential with optical depth (optical depth is the dimensionless product of the extinction coefficient and distance):

$$M(\tau) = M_0 \exp(-\tau) \tag{3}$$

where $M(\tau)$ is the colorfulness of the object at optical depth τ and M_0 is the colorfulness at zero optical depth (i.e., no haze). M_0 is also known as the inherent colorfulness. The colorfulness of the horizon was assumed to be small enough to be taken as zero—the horizon was perceived to be white. This result implies that a JND in colorfulness can be taken to be a JND in haze.

JND in Colorfulness

Estimates of JNDs in colorfulness were based on sets of repeated color matches made during periods when the observing conditions (cloud cover, haze level, and lighting) were judged to be constant or nearly so. Observer Urquito made six sets of repeated matches.[15] Figure 1 is a plot of all the repeated observations of the colorfulness of the red barn roof made by this observer versus optical depth. The exponential fit given by eq 1 is fairly good ($R^2 = 0.68$). The error bars in the figure are twice the standard deviation given in Table 1. They show that one set

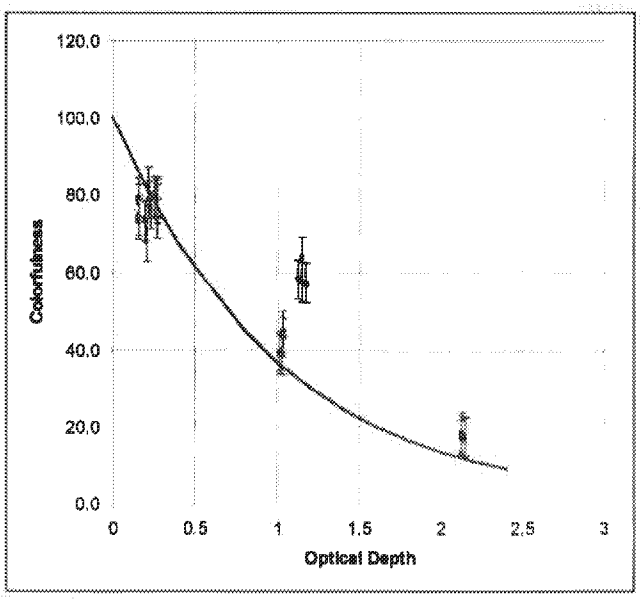


Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

Exhibit E to EAI Comments

ED_002110_00032342-00218

EPA-HQ-2018-002296

Table 1. Repeated measurements of the red barn roof by observer Mahadev.

Date	Time	Scattering Coefficient $(Mm)^{-1}$	Visual Range (km)	Colorfulness Spectra	Colorfulness Perceived	Spectra Hue % Red	Spectra Hue % Blue	Perceived Hue % Red	Perceived Hue % Blue
7/29/95	10:20 a.m.	37	105.7	38.0	42.2	53	47	97	3
7/29/95	10:46 a.m.	39	100.3	38.9	45.6	40	60	92	8
7/29/95	10:54 a.m.	39	100.3	39.9	45.4	38	62	99	1
7/29/95	11:03 a.m.	42	93.1	35.6	46.3	52	48	92	8
7/29/95	11:12 a.m.	42	93.1	37.5	44.9	53	47	93	7
7/25/95	11:49 a.m.	65	60.2	31.2	41.1	50	50	88	12
7/25/95	12:01 p.m.	65	60.2	30.8	45.1	42	58	84	16
7/25/95	12:12 p.m.	65	60.2	30.4	44.1	53	47	91	9
7/25/95	12:19 p.m.	65	60.2	29.4	43.0	54	46	91	9
7/25/95	12:24 p.m.	65	60.2	29.2	48.4	47	53	93	7
8/11/95	9:46 a.m.	157	24.9	37.6	29.2	19	81	97	3
8/11/95	9:57 a.m.	157	24.9	37.2	28.8	22	78	98	2
8/11/95	10:07 a.m.	157	24.9	37.5	29.2	23	77	98	2
8/11/95	10:16 a.m.	161	24.3	36.3	34.9	24	76	98	2
8/11/95	10:21 a.m.	161	24.3	36.7	29.5	23	77	98	2
8/14/95	10:12 a.m.	311	12.6	44.4	18.2	9	91	91	9
8/14/95	10:18 a.m.	312	12.5	44.0	18.4	8	92	97	3
8/14/95	10:30 a.m.	313	12.5	44.8	17.6	7	93	95	5
8/14/95	10:34 a.m.	313	12.5	44.7	18.1	7	93	94	6
8/14/95	10:38 a.m.	313	12.5	44.3	18.3	8	92	94	6
8/18/95	11:00 a.m.	595	6.6	35.3	9.7	2	98	81	19
8/18/95	10:46 a.m.	616	6.4	35.4	6.8	2	98	98	2
8/18/95	10:50 a.m.	616	6.4	35.2	9.4	2	98	91	9
8/18/95	10:53 a.m.	616	6.4	35.0	7.3	2	98	99	1
8/18/95	10:57 a.m.	616	6.4	35.7	10.0	2	98	97	3

of repeated measurements had colorfulness values that deviated much more than 2 sigma from the exponential line. However, the spread of these values about the mean was about the same as other observations for the same optical depth. This shows that the variability in the colorfulness numbers is not affected by systematic observer bias in the average colorfulness, and that the variability will be used to define the JND. The observations of the same target by the other observer are discussed in detail below.

Table 1 gives the results of five sets of repeated matches by observer Mahadev for the roof of a red barn about 3.5 km distant. Table 1 is sorted by the extinction coefficient so that one can easily see that the perceived hue did not change with increasing haze, but that the hue derived from the spectrum changed from red to blue. Colorfulness had the opposite behavior; the perceived values decreased with increasing haze and the values from the spectrum stayed about the same. Two-way analysis of variance was applied to estimate the random error in the sets of repeated measurements in Table 1. This analysis was repeated for both observers' matches of five additional natural targets. The results are given in Table 2. The standard deviation for both observers was 2.05, as calculated from the average of the variances. Although viewing conditions were chosen to be constant, some of this variability was due to small changes in atmospheric conditions.

Based on these results, one can define the JND in colorfulness in many ways. One appropriate definition for this application is based on the following thought experiment. An observer matches a target with the visual colorimeter and determines the colorfulness to be C_1. The extinction coefficient of the atmosphere is decreased, so the colorfulness of the target is increased by an amount ΔC. The observer matches the target again to get the new colorfulness C_2. A JND is defined as the value of ΔC that gives a 95% probability that $C_2 - C_1 > 0$. Assume that C_1 and C_2 are normal random variables with standard deviation s and means C_0 and $C_0+\Delta C$, respectively (statistical analysis of the SEAVS color matching data confirms that this is a good assumption). Then $C_2 - C_1$ is a normal random variable with mean ΔC and standard deviation $2^{1/2}\sigma$. The value of ΔC needed to ensure a 95% probability that $C_1 - C_2 > 0$ is given by $2^{1/2}\sigma F(0.95)$, where $F(0.95)$ is the inverse of the cumulative standard normal distribution and is equal to 1.645. Thus, the colorfulness JND is taken to be $2^{1/2}\sigma F(0.95) = 2.326\sigma$. From Table 2, using the data for both observers gives $\sigma = 2.05$, and a 1 colorfulness JND is 4.8. This value of σ includes the effects of small random variations in natural illumination, which should be included for this application because they are inevitably present, but makes the value of a colorfulness JND a bit larger than it would be otherwise.

Exhibit E to EAI Comments

ED_002110_00032342-00219

EPA-HQ-2018-002296

Table 2. Standard deviations of colorfulness for repeated matches of natural targets.

Target	Observer M	Observer U	Distance (km)
White silo	0.91	1.33	3.54
Red roof	1.93	2.41	3.54
Near green meadow	2.93	2.15	3.86
Green hills	2.15	3.46	5.15
Far green meadow	1.45	1.64	10.46
Horizon sky	1.53	1.19	
Average	1.92	2.17	
Number of observations	55	60	

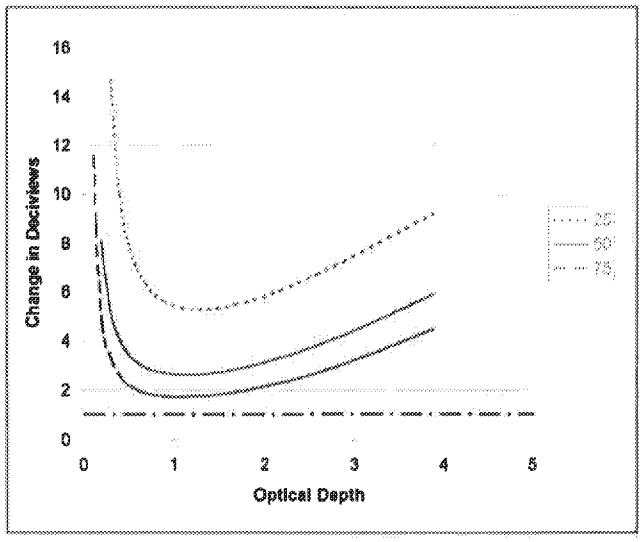


Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

Deciviews and Colorfulness JNDs

Relationships between colorfulness, deciviews, and optical depth are derived below; these will be applied to test the validity of the properties of deciviews given in the regional haze regulations.

From eqs 2 and 3, an expression for deciviews v as a function of colorfulness M is derived:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \tag{4}$$

For a given optical depth and inherent colorfulness, the equations above were used to calculate the change in deciviews needed to give a 1-JND increase in colorfulness, using 4.8 as a JND. Figure 2 is a plot of the results as a function of optical depth for objects with three levels of inherent colorfulness. These levels of inherent colorfulness represent a reasonable range for natural targets.[12] As might be expected, more colorful objects are more sensitive to changes in atmospheric haze. Perhaps unexpectedly, the figure shows that landscape features at a distance corresponding to an optical depth of 1–2 are the most sensitive to changes in extinction as measured by deciviews. This range corresponds to one quarter to one half of the visual range. Landscape features outside this range are much less sensitive to changes in haze. If the deciview scale were perceptually uniform, as claimed in the regional haze rules, then the lines in the figure would be horizontal, or at least approximately so. However, the change in deciviews needed to produce a 1-JND change in colorfulness varied a great deal with optical depth and inherent colorfulness. The figure also shows that a 1-JND change in colorfulness always requires more than a 1-deciview change, sometimes much more.

DISCUSSION AND CONCLUSIONS

Regional atmospheric haze affects visibility by producing a visible haze layer that limits the visual range, reduces contrast, and deceases the colorfulness of objects seen though the haze. Of these three effects of haze, the decrease in colorfulness may be the most important and sensitive visual cue. Visual range is not often useful for judging the effects of small changes in extinction. For example, a change in visual range from 50 to 60 km will not be noticed if the most distant landscape feature is at 25 km. The effect of haze on contrast is a better candidate as an indicator of change in haze; however, perceived contrast, like perceived hue, is affected in a nonlinear fashion by the semitransparent nature of haze and is not a sensitive indicator of changes in atmospheric haze.[16] Experimental data have shown that colorfulness is a sensitive measure of changes in haze, so this article has used it to define just-noticeable changes in atmospheric haze.

A just-noticeable decrease in atmospheric haze is defined as a decrease in extinction that would produce a 95% probability of a measurable increase in colorfulness of an object seen through the haze. From the experimental evidence from the two young male observers, a JND in colorfulness was 4.8. For the population in general, this number is certainly too low, since all visual functions decline with age. Thus, the conclusions below about the deciview scale based on this number are understated for the general population.

Analysis of the experimental data showed that for a JND in atmospheric haze as defined above:

(1) The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable

Exhibit E to EAI Comments

ED_002110_00032342-00220

EPA-HQ-2018-002296

varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness.

(2) A 1-deciview change is never noticeable.

What are the implications of these results for measuring progress toward reducing regional haze using the deciview metric? This is difficult to judge because the current proposals are very complex, using particulate measurements and relative humidity to estimate the extinction coefficient and average deciviews for the 20% most-impaired and 20% least-impaired days. The goal is to show no change on the least-impaired days and improvement on the most-impaired days, leading to natural conditions by 2064.[17]

The results of this article highlight a possible flaw in this regulatory scheme based on the deciview metric. An unstated assumption is that the nature of the scenic vista can be ignored—that is, a given deciview change will affect the perception of all landscape features in all scenes in the same way. Figure 2 shows that this is approximately true only if all the important landscape features have nearly the same inherent colorfulness and are at distances that correspond to an optical depth of between 1 and 2, or about one quarter to one half of the visual range. In this limited case, the deciview is indeed a uniform metric. However, most scenic vistas do not fit these restrictions and, by Figure 2, will require greater decreases in extinction as measured by deciviews to show a perceptible change. The result is that the emission reductions required by the proposed regulatory analysis are likely to produce much smaller improvements in perceived effects of regional haze than expected. The EPA guidance documents provide an example of an eastern scenic vista with a baseline of 27 deciviews and natural conditions of 11.[17] The decrease in extinction to reach natural conditions by 2064 is 0.35 deciview/yr, or 1.75 deciviews in five years. This five-year reduction should, according to the regulations, result in a noticeable change in regional haze. However, the results herein predict that there would very likely be no noticeable difference in any actual scenic vista in the region as a result of the required emission reductions.

Regional haze rules also call for a uniform rate of improvement in visibility (measured in deciviews) that is needed to go from current conditions to natural conditions by 2064. Since the deciview scale is not uniform in perception over a wide range of visibility conditions, this requirement is also flawed and will not result in uniform improvement in perceived visibility.

ACKNOWLEDGMENTS

The funding for this project was provided by the Electric Power Research Institute under Contract EP-P5419/C2683. The author would like to thank Dr. Naresh Kumar for his support and discussions leading to this work, and Drs. Shudeish Mahadev and Santiago Urquito for their careful and diligent work as the observers in the field study.

REFERENCES

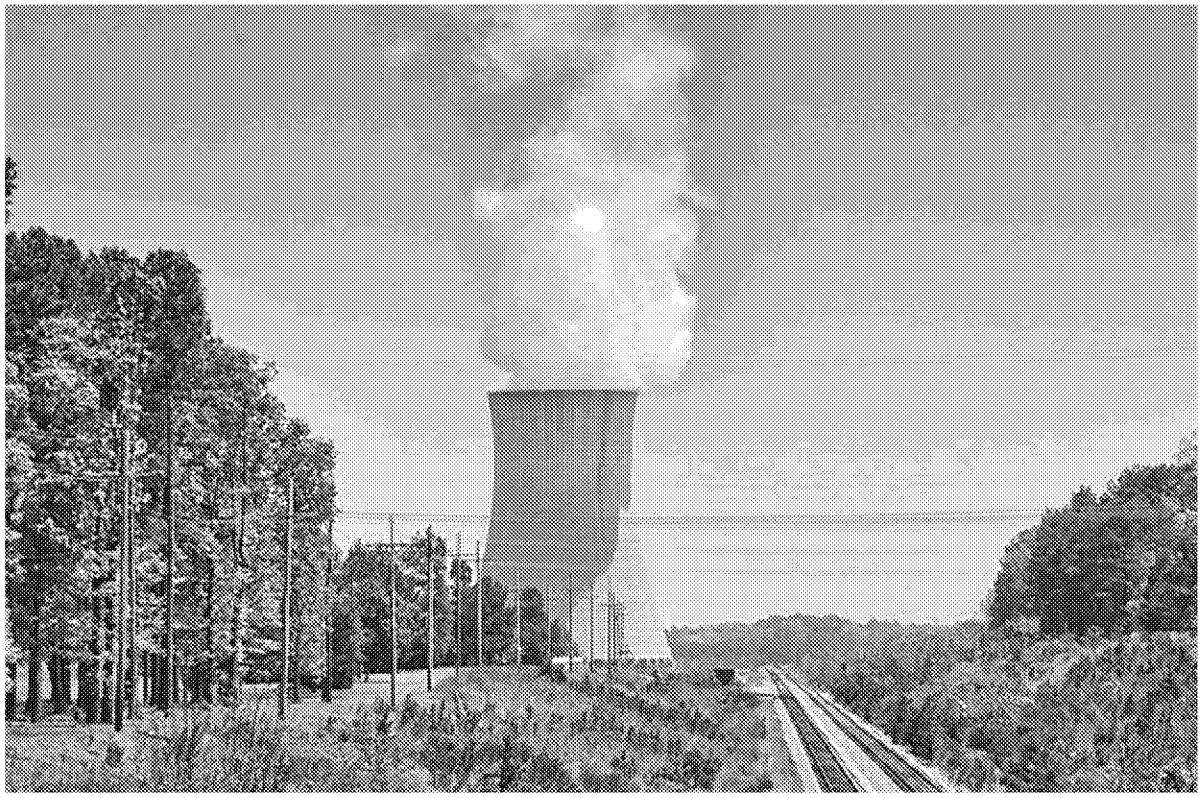
1. *Fed. Regist.* 1999, *64* (126), 35713-35774.
2. Pitchford, M.; Malm, W. Development and Applications of a Standard Visual Index; *Atmos. Environ.* 1994, *28*, 1049-1054.
3. Palmagne, J.C. *Elements of Psychophysical Theory;* Oxford University Press: New York, 1985.
4. Middleton, W.E.K. *Vision through the Atmosphere;* University of Toronto Press: Toronto, Ontario, 1952; p 122.
5. Andrews, E.; Saxena, P.; Musarra, S.; Hildemann, L.M.; Koutrakis, P.; McMurry, P.H.; Olmez, I.; White, W.H. Concentration and Composition of Atmospheric Aerosols from the 1995 SEAVS Experiment and a Review of the Closure between Chemical and Gravimetric Measurements; *J. Air & Waste Manage. Assoc.* 2000, *50*, 648-664.
6. Blando, J.D.; Porcja, R.J.; Li, T.H.; Bowman, D.; Lioy, P.J.; Turpin, B.J. Secondary Formation and the Smoky Mountain Organic Aerosol: An Examination of Aerosol Polarity and Functional Group Composition during SEAVS; *Environ. Sci. Technol.* 1998, *32*, 604-613.
7. Dick, W.D.; Ziemann, P.J.; Huang, P.F.; McMurry, P.H. Optical Shape Fraction Measurements of Submicrometer Laboratory and Atmospheric Aerosols; *Measure. Sci. Technol.* 1998, *9*, 183-196.
8. Ames, R.B.; Hand, J.L.; Kreidenweis, S.M.; Day, D.E.; Malm, W.C. Optical Measurements of Aerosol Size Distributions in Great Smoky Mountains National Park: Dry Aerosol Characterization; *J. Air & Waste Manage. Assoc.* 2000, *50*, 665-676.
9. Hand, J.L.; Ames, R.B.; Kreidenweis, S.M.; Day, D.E.; Malm, W.C. Estimates of Particle Hygroscopicity during the Southeastern Aerosol and Visibility Study; *J. Air & Waste Manage. Assoc.* 2000, *50*, 677-685.
10. Malm, W.C.; Day, D.E.; Kreidenweis, S.M. Light Scattering Characteristics of Aerosols as a Function of Relative Humidity: Part I—A Comparison of Measured Scattering and Aerosol Concentrations Using the Theoretical Models; *J. Air & Waste Manage. Assoc.* 2000, *50*, 686-700.
11. Malm, W.C.; Day, D.E.; Kreidenweis, S.M. Light Scattering Characteristics of Aerosols at Ambient and as a Function of Relative Humidity: Part II—A Comparison of Measured Scattering and Aerosol Concentrations Using Statistical Models; *J. Air & Waste Manage. Assoc.* 2000, *50*, 701-709.
12. Henry, R.C.; Mahadev, S.; Urquito, S.; Chitwood, D. Color Perception through Atmospheric Haze; *J. Opt. Soc. Am., A. Optics, Imaging Sci. & Vision* 2000, *17*, 831-835.
13. Henry, R.C.; Shibata, T.; Chitwood, D. Construction and Operation of a Video-Based Visual Colorimeter for Atmospheric Research; *Atmos. Environ.* 1994, *28A*, 1065-1069.
14. Mahadev, S.; Henry, R.C. Application of a Color Appearance Model to Vision through Atmospheric Haze; *Color Resh. & Appl.* 1999, *24*, 112-120.
15. Mahadev, S. Quantifying the Color Appearance of Objects Viewed through Atmospheric Haze. Ph.D. Dissertation, University of Southern California, Los Angeles, CA, 1998.
16. Henry, R.C. Psychophysics, Visibility, and Perceived Transparency; *Atmos. Environ.* 1987, *21*, 159-164.
17. U.S. Environmental Protection Agency. *Draft Guidance for Tracking Progress under the Regional Haze Rule;* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards: Research Triangle Park, NC, September 27, 2001.

About the Author

Dr. Ronald C. Henry is professor of Civil and Environmental Engineering at the University of Southern California, Department of Civil and Environmental Engineering, 3620 South Vermont Ave., Los Angeles, CA 90089-2531; e-mail: *rhenry@usc.edu.*

ED_002110_00032342-00221

FOSTER WHEELER NORTH AMERICA CORP
53 Frontage Road,
Hampton, NJ 08827-9000, USA



TANGENTIAL LOW NOx (TLN3) SYSTEM
FOR

ENTERGY
WHITE BLUFF UNITS 1& 2

Proposal No. 65-130582-00 Rev. 0
October 13, 2011

Exhibit F to EAI Comments

PROPIETARY AND CONFIDENTIAL INFORMATION

This proposal and the information, design and material contained and/or illustrated herein (hereinafter "proprietary and confidential" material), are the property of FOSTER WHEELER NORTH AMERICA CORP, (FWNAC) and is submitted, lent and furnished to you in the strict confidence with the expressed understanding that you shall not use said proprietary material for any purpose other than for the evaluation of this proposal or reproduce, copy, lend, dispose of, or disclose said proprietary material to anyone outside receipt organization. By receiving said proprietary material you agree not to use the same in any way injurious to the interest of FOSTER WHEELER NORTH AMERICA CORP, and agree to return to same upon request.

3.3 Foster Wheeler's Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp's (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and / or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should complement the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All T-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example our on-line real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

Currently there are numerous tangentially coal fired utility units equipped with Foster Wheeler's TLN systems (see Experience List in Appendix). Fuels being fired range from lignite and PRB through low and higher sulfur eastern bituminous coals. NOx reductions exceeding 70 percent and NOx levels below 0.10 lb/MBtu are being achieved.

3.3.2 FWNAC's TLN Systems

Foster Wheeler's Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as "overfire air". Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 3.**

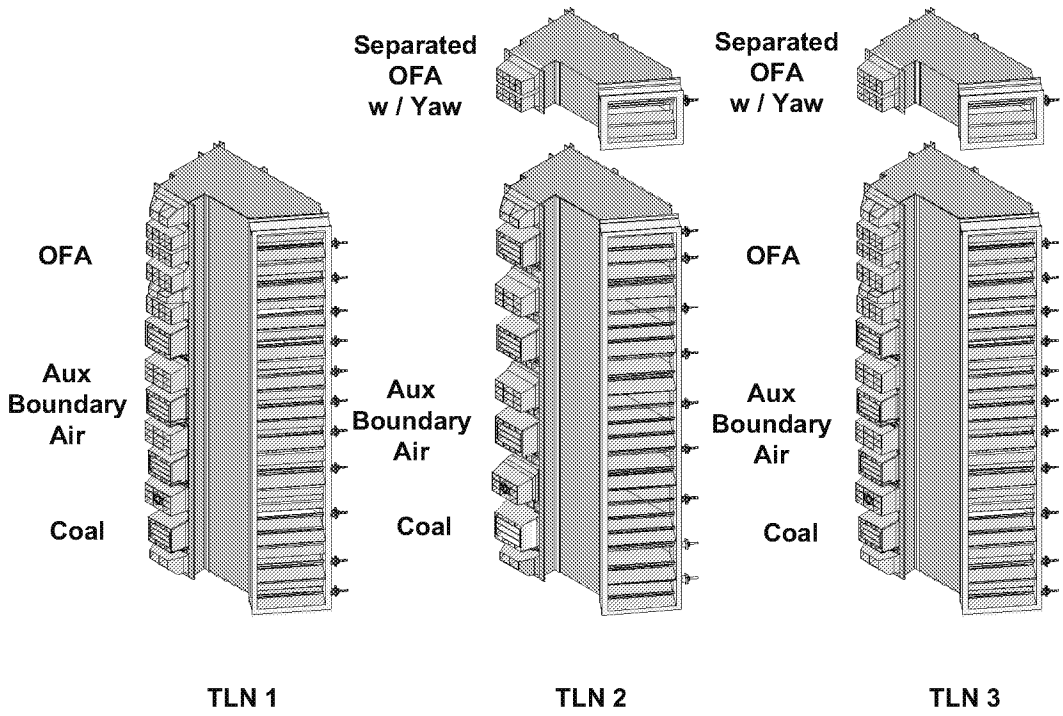


Figure 3 - FWNAC Tangential Low NOx (TLN) Configurations

Foster Wheeler's **TLN2** system consists of adding a single level of separated overfire air above the main firing zone to provide the required vertical air staging effect. Due to increased spacing from the upper coal elevation, separated overfire arrangements provide significantly higher NOx reduction efficiencies as compared with "in-windbox" arrangements. Nozzle tips and/or air flow control dampers in the main windboxes are often resized or modified as part of such retrofits. Foster Wheeler's proprietary computer-modeling program is used to ensure that proper airflow distribution control and air/coal mixing is maintained throughout the unit load range with the new SOFA addition.

The **TLN3** system consists of adding a single level of separated overfire air to units that already have an in-windbox OFA. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire air windbox level. Nozzle tips and air flow control dampers in the main windboxes are often upgraded or modified in accordance with computer modeling results or to meet specific unit or fuel requirements. These modifications ensure that proper airflow distribution control and air/coal mixing is maintained. Both the TLN2 and TLN3 have demonstrated up to 75% NOx reduction.

3.3.3 Combustion Computational Fluid Dynamics - Option

Foster Wheeler is offering a Computational Fluid Dynamics (CFD) study of furnace thermodynamics to validate boiler performance before and after installation of the SOFA system. CFD analysis is an inherently man-hour intensive process because the ability of the CFD model to provide accurate predictions is predicated on the accuracy of the model and thus requires that each existing system (boiler) be manually detailed in the program prior to use. CFD can therefore be a somewhat expensive undertaking.

FWNAC feels obligated to inform Entergy that the results of CFD modeling have never altered the design, predictions or guarantees associated with a TLN retrofit and can therefore be somewhat of an extraneous exercise unless applied to validate a specific, unique design feature. In other words, should Entergy find the cost/benefit associated with use of CFD to be less than satisfactory, solace should be found in the fact that it will only service to confirm the design being offered.

Should Entergy desire to proceed with use of Foster Wheeler's Combustion CFD program, on both White Bluff units, the model will extend from the burner fronts up through the leading edge of the first bank of the finishing superheater.

Vital to any OFA design is full penetration of the air jets into the furnace gas stream to insure turbulent mixing with the bulk of the rising flue gases. This is accomplished by choosing appropriate nozzle velocities and sizes. Foster Wheeler has studied jet

4 DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for White Bluff Units 1 and 2

Based on Entergy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing our TLN3 system. This system will consist of the following specific components and features.

The proposed FWNAC modifications to Entergy's White Bluff Units 1 and 2 are shown on FWNAC proposal drawings attached in the Appendix.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of eight (8) new SOFA windboxes. To minimize physical changes to the boiler house, the new Overfire Air windboxes would be installed in the front and rear walls above the existing windboxes. The SOFA windboxes would be designed to supply the appropriate amount of combustion air as Overfire Air. Each new windbox will be provided along with new water wall panels and the necessary connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers with actuators (Kinetrol 147-130-1900 Fail Open Spring return Actuator with Siemens PS2 Single Acting Smart Positioner) and static pressure taps to provide total Overfire Air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

   A CFD air flow model will be developed that includes the secondary air ducts, SOFA ducts, windboxes and burners to ensure balanced air flow.

b) Platform, railing, sootblowers, and sootblower piping may need to be modified where required to accommodate the addition of the separated over fire air system.

c) New FW Double Shroud (DS) type nozzle tips and associated linkage hardware will be supplied. These will be 100% compatible with the existing coal nozzle and tilt linkage. The new nozzle tip, which includes a patented (US Patent No. 6,260,491) cooling feature, will also be reconfigured to further help stage more air to the SOFA compartments to provide additional NOx reduction benefits.

d) The 23¼ inch high upper CCOFA compartment will be modified with a crotch cooling plate on the top and a restrictor plate on the bottom to reduce the outlet height to 19 ¼ inches. A new, one piece FWNAC DS style nozzle tip will be

provided. This tip will be the same tip as the lower CCOFA and bottom air tips. This interchangeability will reduce stocking and maintenance costs.

e) The 23¼ inch high lower CCOFA compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the upper CCOFA nozzle tip.

f) The fuel piping to the refuse compartment is currently blanked off, with no future plans for firing this compartment. As a top end air, this 24 inch high compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the CCOFA nozzles.

g) The outlet flow area of each 27¼ inch high auxiliary air compartment will be reduced with restrictor plates for velocity compensation. Each compartment will be fitted with one (1) new, one piece FWNAC DS style type boundary air auxiliary nozzle tip. The nozzle tip is designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions and fireball shaping while maximizing combustion efficiency.

h) The 27¼ inch high oil warm-up compartment will also be reduced with restrictor plates for velocity compensation and modified with a similar tip, with the center of the tip to accommodate the existing oil gun. However, due to the presence of the oil warm-up gun, this tip will not yaw.

i) The existing bottom end air compartments will be fitted with new, one piece reduced free area nozzle tips. These tips will be interchangeable with the CCOFA tips.

j) As an integral part of the TLN3 system, the Lower Furnace Stoichiometry Control (LFSC) system will be provided. These systems help reduce the dark lower furnace hopper conditions typically associated with deep-staged combustion systems. It is comprised of a single air nozzle tip with external manual tilt installed in the bottom end air compartment. This will be used to direct combustion air into the lower furnace hopper area, further controlling lower furnace smoky conditions, slagging and CO formation that might occur during ultra low NOx deep staged operation.

k) All coal, auxiliary air and CCOFA windbox compartments will be modified with FWNAC's damper venturi plates to improve air flow distribution control over a larger load range.

7 PERFORMANCE GUARANTEES & CONDITIONS

7.1 Performance Guarantees

The following Performance Guarantees contained within this section 7.1 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal or in the specification fill-in sheets shall not be construed as performance guarantees.

- Three (3) one hour tests will be conducted for NOx, CO, LOI, main steam temperature and reheat steam temperature at MCR. Three (3) one hour tests will also be conducted for main and reheat steam temperatures at Guarantee Point Load and Control Load. The guarantees will be considered met if the average of each guarantee value over the three (3) test periods meets the guarantee values offered below by FWNAC.

  A thirty (30) day rolling average test will also be conducted for NOx and CO emissions. This test may be conducted for 45 day period to allow for selection of the data for the 30 day period. Only data to be included will be that while the unit is operating between Control Load and MCR. Data will be excluded while the unit is at upset condition.

- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Emissions

<u>MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.12 lb/MBtu for the average of three (3) one hour tests**

<u>Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.14 lb/MBtu over a 30 day period**

7.1.2 Carbon Monoxide (CO)

MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) for the average of three (3) one hour tests**

Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) over a 30 day period**

7.1.3 Fly Ash LOI

MCR (6,023 klb/hr main steam flow)

- **Fly ash LOI will average less than or equal to 1.0% for the average of three (3) one hour tests**

7.1.4 Superheat (SH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Control Load (3,000 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

7.1.5 Reheat (RH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **1000 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

July 30, 2015
Ref: Tangential Low NOx

Michael P. Fallon, P.E.
Entergy – Boiler Process Owner
White Bluff & Lake Catherine

Dear Mike;

Tangential low NOx systems that use separated overfire air are designed to provide significant reductions in NOx across the control range of the boiler, which is normally from 50 to 100 percent of steam flow. These systems work in the control range because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers. When this is done combustion zone airflow is sub stoichiometric and oxygen there is reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing.

Overfire air cannot be fully utilized for NOx abatement below the control range because net heat input is not sufficient to allow the combustion zone in the furnace to safely run in a sub stoichiometric condition. When a boiler runs below the control range NOx concentrations can be elevated above the levels achievable at higher loads, even though the tons of NOx emitted is less due to the reduced amount of fuel and air.

I hope this memo answers your question.

Steve deMello
Project Manager
Amec Foster Wheeler North America Corp.
53 Frontage Road, PO Box 9000
Hampton, NJ 08827-9000

53 Frontage Road
PO Box 9000
Hampton, NJ 08827-9000
USA
amecfw.com

EVALUATION OF THE CALPUFF MODELING SYSTEM MARGIN OF ERROR FOR A BART ANALYSIS

Entergy Arkansas, Inc. > Lake Catherine Plant

Entergy
THE POWER OF PEOPLE™

Prepared By:

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661 -8100
Fax: (972) 385-9203

August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit H to EAI Comments

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. BACKGROUND 2-1
2.1. Class I Areas 2-1
2.2. Proposed BART for the Lake Catherine Plant 2-2
2.2.1. NO_X BART 2-2

3. MODELING METHODOLOGY 3-1
3.1. Model Selection 3-1
3.2. Modeled Scenarios 3-1
3.3. Background Values 3-1
3.4. Modeled Versus Measured Statistics and Margin of Error 3-2

4. RESULTS 4-1
4.1. Modeled Versus Measured Statistics and Margin of Error 4-1
4.1.1. Caney Creek Measured Versus Modeled Comparisons 4-3
4.1.2. Upper Buffalo Measured Versus Modeled Comparisons 4-5

5. CASE STUDIES 5-1
5.1. Mohave Generating Station 5-1
5.2. Craig Station 5-2
5.3. North Dakota SIP 5-2
5.4. Colstrip Generating Station 5-3

6. CONCLUSIONS 6-1

LIST OF FIGURES

Figure 2-1. Location of Lake Catherine Plant with Respect to Arkansas Class I Areas 2-1

Figure 4-1. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART 4-3

Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART 4-4

Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART 4-4

Figure 4-4. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART 4-5

Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART 4-6

Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART 4-6

LIST OF TABLES

Table 2-1. Baseline Visibility Impairment 2-2

Table 4-1. Summary of Modeled Versus Measured Statistics 4-1

Table 4-2. Projected Visibility Improvement from Lake Catherine Margin of Error 4-2

Table 5-1. Mohave Visibility Impairment – Before and After 5-1

Table 5-2. NDDH Measured versus Modeled Nitrate Concentrations 5-3

1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. As part of the FIP, EPA proposed nitrogen oxide (NO_X) controls for the Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4, which is subject to Best Available Retrofit Technology (BART).[1] In order to justify the visibility improvement as a result of installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system (CALPUFF) without assessing the reliability of the model to predict small changes in visibility.

Entergy completed a quantitative analysis to evaluate the margin of error in the CALPUFF analysis for Lake Catherine Unit 4 and determined the visibility improvements relied upon in the proposed Arkansas FIP are within the model's margin of error. Specifically, the incremental visibility improvements predicted by CALPUFF at the Caney Creek Wilderness Area (Caney Creek) and Upper Buffalo Wilderness Area (Upper Buffalo) Class I areas are within the margins of error calculated for each Class I area. Moreover, the visibility improvement values are within the *lowest* margin of error for both Class I areas. Because of this, EPA cannot *reasonably anticipate* visibility benefits from the proposed controls for Lake Catherine Unit 4. *See National Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1146–47 (9th Cir. 2015) ("Montana Case") (holding that EPA must offer a reasoned explanation of its conclusion that a visibility improvement could be reasonably anticipated when the improvement is within CALPUFF's margin of error).

This report is organized as follows: Section 2 provides background on the Lake Catherine Plant and EPA's proposed BART requirements, Section 3 outlines the methodology used in the Lake Catherine analysis, Section 4 summarizes the results of the analysis, and Section 5 presents several case studies comparing modeled values to monitored values.

[1] Proposed Arkansas Regional Haze FIP, 80 Fed. Reg. 18,943 (Apr. 8, 2015).

2. BACKGROUND

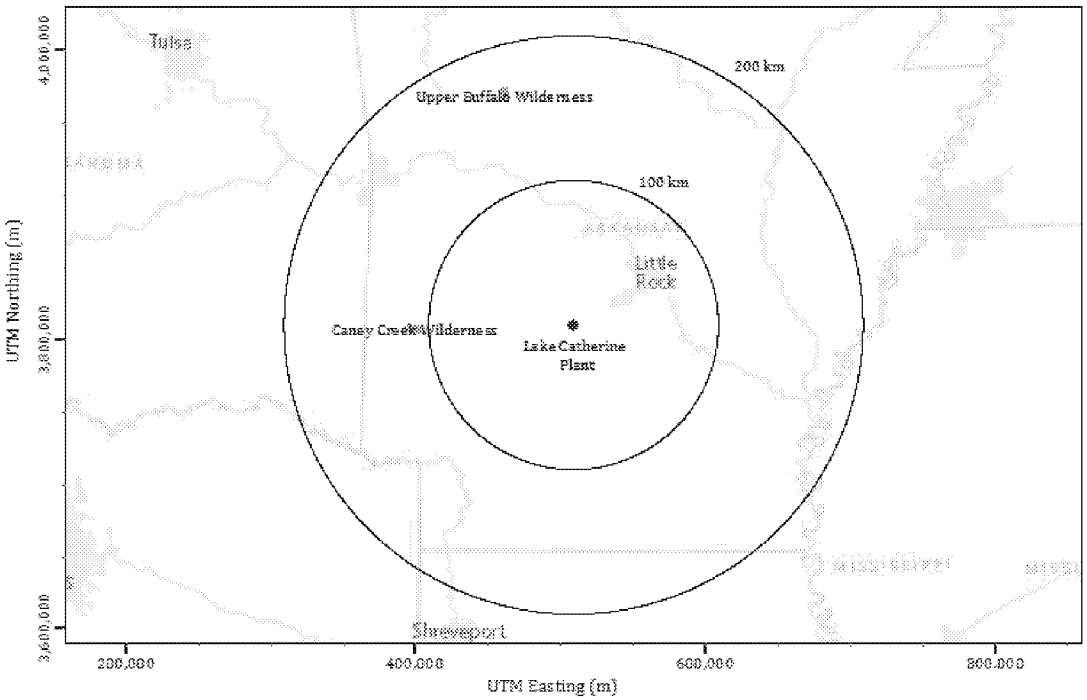
Entergy owns and operates the Lake Catherine Plant located at 141 W. County Line Road in Malvern, Arkansas. The Lake Catherine Plant operates one emission unit – Unit 4 – that is an affected source under the BART provisions of the EPA's Regional Haze Rule, which is codified in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. Unit 4 is a tangentially-fired boiler with a nominal heat input rate of 5,850 Million British thermal units per hour (MMBtu/hr) and a nominal net power rating of 558 megawatts (MW). The boiler is permitted to fire natural gas and No. 6 fuel oil; however, the unit has not fired fuel oil since the 2001-2003 baseline period and Entergy does not plan to burn fuel oil in the unit in the foreseeable future.

On April 18, 2015, EPA proposed a FIP to address requirements related to regional haze for those portions of the Arkansas State Implementation Plan (SIP) that were disapproved on March 12, 2012.[2] The FIP includes NO_X BART requirements for Lake Catherine Unit 4.

2.1. CLASS I AREAS

Per the FIP, there are two (2) Class I areas in Arkansas that are impacted by Unit 4 at the Lake Catherine Plant: Caney Creek and Upper Buffalo. Caney Creek is approximately 100 km west and Upper Buffalo is approximately 160 km north of the Lake Catherine Plant. The locations of the Class I areas with respect to the Lake Catherine Plant are shown in Figure 2-1 below. Table 2-1 summarizes the baseline visibility impairment attributable to Unit 4 at each of these Class I areas as determined by CALPUFF.[3]

Figure 2-1. Location of Lake Catherine Plant with Respect to Arkansas Class I Areas



[2] FR Vol. 80, No. 84, May 1, 2015.

[3] Ibid.

Table 2-1. Baseline Visibility Impairment

Emission Unit		Caney Creek	Upper Buffalo
Unit 4	Maximum (Δdv)[1]	3.480	2.044
	98th Percentile(Δdv)[1]	1.371	0.489

1. Values shown are for natural gas combustion.

2.2. PROPOSED BART FOR THE LAKE CATHERINE PLANT

The proposed NO_X BART for Lake Catherine Unit 4 is summarized below.

2.2.1. NO_X BART

In the proposed FIP, EPA determined that NO_X BART for Unit 4 for the natural gas scenario is an emission limit of 0.22 pounds per MMBtu (lb/MMBtu) on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of Burners out of Service (BOOS).[4] The projected visibility improvement at Caney Creek and Upper Buffalo based on CALPUFF modeling is shown in Table 2-2 below.

Table 2-2. Projected Visibility Improvement

Emission Unit	Pollutant	Caney Creek (Δdv)	Upper Buffalo (Δdv)
Unit 4	NO_X	0.596	0.248

[4] Per the FIP, "BOOS is a staged combustion technique in which fuel is introduced through operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners."

3. MODELING METHODOLOGY

In completing the BART five factor analysis for Lake Catherine Unit 4, EPA relied on the visibility improvement as predicted by CALPUFF without assessing the ability of the model to accurately predict small changes in visibility. In order to assess the magnitude of visibility that could reasonably be anticipated for the Lake Catherine case, Trinity conducted a margin of error analysis similar to the one completed for the Colstrip Generating Station ("Colstrip Station") by TRC Environmental Corporation (TRC) that was the basis for PPL Montana's comments on the CALPUFF model in the Montana Case.[5] The following sections outline the methodology that was used to complete this analysis for the Lake Catherine Plant. This study is necessary due to the dissimilarities in the geographical and meteorological conditions between the Lake Catherine Plant and the Colstrip Station at issue in the Montana Case.

3.1. MODEL SELECTION

The BART Guidelines recommend using the CALPUFF Modeling System to determine the visibility impairment attributable to a BART-eligible source. This analysis was completed using CALPUFF Version 5.84, POSTUTIL Version 1.52, and CALPOST Version 6.221, the model versions utilized in the Arkansas BART analyses. Entergy used refined meteorological data consistent with the meteorological data used for other BART sources in Arkansas. On July 26, 2012, the Arkansas Department of Environmental Quality (ADEQ) updated its original (June 7, 2006) protocol including CALPUFF modeling components and the background concentrations in CALPOST. The CALMET data and parameters are based on the modeling protocol that was first submitted on January 23, 2008 on behalf of Oklahoma Gas & Electric and upon which all recent BART analysis in Arkansas have been based. This protocol summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources.

3.2. MODELED SCENARIOS

As part of this analysis Entergy modeled the following three scenarios:

1. ALL BART: Includes all sources subject to BART modeled using Pre-BART representations;
2. Pre-BART: Includes only the Lake Catherine Plant BART eligible source modeled based on its current permit representations; and
3. Post-BART: Includes only the Lake Catherine Plant BART eligible source modeled using the Post-BART emission rate and stack parameters.

3.3. BACKGROUND VALUES

The primary objective of this analysis was to compare the model predicted data to monitored data at each Class I area to identify the modeling margin of error in predicting visibility compared to observed values. BART modeling using CALPUFF is conducted to determine the impact of a facility on a Class I area without consideration of emissions/impacts from other sources. This type of analysis uses only natural background

[5] *See* "Accuracy of Visibility Protocol Modeling in BART Evaluations" prepared by Gale F. Hoffnagle, TRC Environmental Corporation, June 15, 2012. PPL Montana relied on this analysis in its comments alleging that the incremental visibility improvement predicted by EPA at Colstrip Station were within CALPUFF's margin of error. *See* PPL Montana, LLC's Comments on Proposed Regional Haze Federal Implementation Plan for the State of Montana at 8-11, Docket ID EPA-R08-OAR-2011-0851-0211 (2012).

conditions, referred to by EPA as a "clean background" analysis. As such, comparing model predicted output directly from the CALPUFF Modeling System to monitoring data does not represent a like-kind comparison as it is missing contribution from other sources. In order to obtain an estimate of the impact of other emission sources (i.e., point, non-point, mobile, biogenic, etc.), Entergy obtained a background value from CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.[6] The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenarios and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

3.4. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Entergy calculated the average difference between modeled values obtained using the CALPUFF Modeling System (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three (3) modeling scenarios described previously. Unlike BART analyses where the 98th percentile values are compared to the dv impact level, Entergy utilized the regional haze design value format of average worst 20% days for this analysis. Since the CENRAP background value is from the 2002 calendar year, this comparison was only completed for 2002. Specifically the following comparisons were made:

- Modeled vs Measured 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.
- Measured vs. Modeled 20% Worst Days: The worst 20% days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.
- Measured and Modeled 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected and compared with the worst 20% days based on CALPUFF modeling results disregarding temporal correlation.

Entergy used these average differences to determine the lowest overall margin of error for each Class I area. Entergy also examined how the modeled visibility impacts from the Lake Catherine Pre-BART scenario, excluding background, compared with the IMPROVE measurements at Caney Creek and Upper Buffalo. This provides an indication of the magnitude of the contribution from Lake Catherine Unit 4 to the total visibility impairment reflected in the IMPROVE measurements.

[6] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool - CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

4. RESULTS

The following sections summarize the results of the analyses completed for the Lake Catherine Plant.

4.1. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Table 4-1 below summarizes the average difference between the modeled versus measured 20% worst days (20% worst-days based on measured values), measured versus modeled 20% worst days (20% worst-days selected based on modeled values), and modeled and measured 20% worst days (comparison of values from 20% worst modeled days and 20% worst measured days not temporally paired). Consistent with the study assessing CALPUFF modeling for the Colstrip Station, CALPUFF consistently over predicts when compared to IMPROVE observations.

Table 4-1. Summary of Modeled Versus Measured Statistics

Model Scenario	Modeled vs. Measured Statistics	CACR (Mm-1)	CACR (dv)	UPBU (Mm-1)	UPBU (dv)
All BART Sources	Modeled vs. Measured 20% Worst Days Average Difference	28.69	1.40	22.18	1.09
	Measured vs. Modeled 20% Worst Days Average Difference	45.64	6.47	51.65	6.09
	Modeled & Measured 20% Worst Days Average Difference	25.52	1.16	20.09	0.93
Lake Catherine Pre-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.60	1.39	21.98	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.79	5.89	64.46	7.86
	Modeled & Measured 20% Worst Days Average Difference	27.88	1.34	21.50	1.04
Lake Catherine Post-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.81	1.40	22.01	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.25	5.85	66.86	8.24
	Modeled & Measured 20% Worst Days Average Difference	28.42	1.38	21.74	1.05
	Average	**32.95**	**2.92**	**34.72**	**3.16**
	Maximum	**45.64**	**6.47**	**66.86**	**8.24**
	Minimum	**25.52**	**1.16**	**20.09**	**0.93**

The lowest calculated margin of error at Upper Buffalo is 0.93 dv. A larger margin of error, 1.16 dv, was calculated for Caney Creek. As shown in Table 4-2 below, the CALPUFF predicted visibility improvement at Caney Creek and Upper Buffalo obtained from the Arkansas FIP is within the margin of error calculated for each Class I area. Moreover, the predicted visibility improvement is within the lowest margin of error of 0.93 dv regardless of the Class I area. This analysis suggests that the formulation associated with CALPUFF forces the model to predict a value for a given scenario regardless of the accuracy of the value. Moreover, the model predicted number at these lower ranges may not necessarily result in the actual visibility improvement, as the numbers can very well be within the uncertainty in the prediction.

According to the BART guidance, use of 98th percentile or 8th highest value of model prediction is used to reduce the effect of uncertainty in the CALPUFF models. The Lake Catherine analysis uses the worst 20% days or 24 high values to determine the margin of error, thus providing additional data points for the analysis rather than just one data point (i.e., 98th percentile). The use of worst 20% days is consistent with the calculations associated with the reasonable progress goals. Use of the 98th percentile does not address the real issue, that the CALPUFF model is predicting visibility improvements for Lake Catherine that fall within the model's margin of error for this case, thus the projected visibility improvements cannot be *reasonably anticipated* as is required by

the Clean Air Act. As stated in the Montana Case, "The issue is not the *perceptibility* of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye."[7] EPA has failed to address how CALPUFF can be used as the basis for BART determinations when the predicted visibility improvements in many cases are lower than the calculated margin of error. Due to the uncertainty in the model's ability to predict small visibility improvements, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated.*

Table 4-2. Projected Visibility Improvement from Lake Catherine Margin of Error

Emission Units	Baseline Visibility Impact (dv)	Visibility Improvement from Baseline (Δdv)	Calculated Margin of Error (dv)
Lake Catherine Unit 4			
Caney Creek Wilderness Area	1.371	0.596	1.16
Upper Buffalo Wilderness Area	0.532	0.248	0.93

[1] Data obtained from the proposed AR FIP (FR Vol. 80, No. 67) - https://federalregister.gov/a/2015-06726

[7] Montana Case, at 1147.

4.1.1. Caney Creek Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 at Caney Creek.

Figure 4-1. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

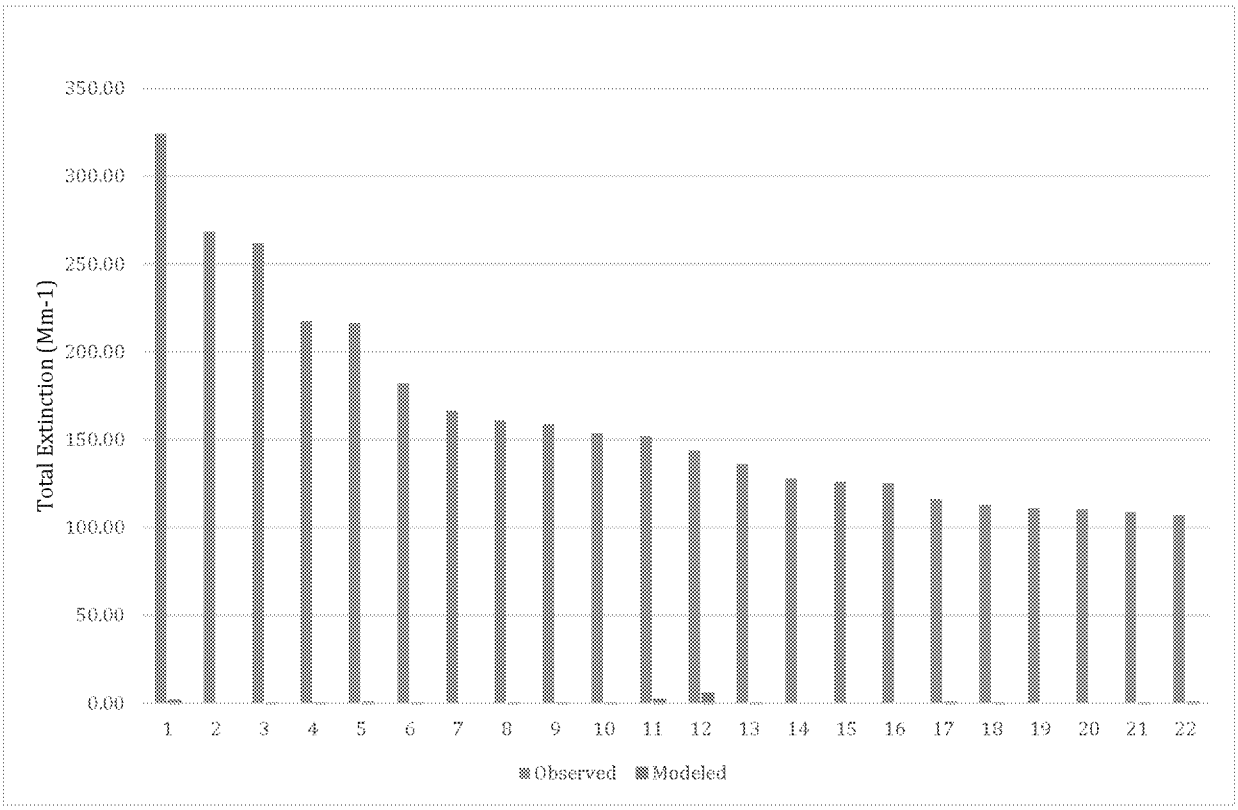


Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

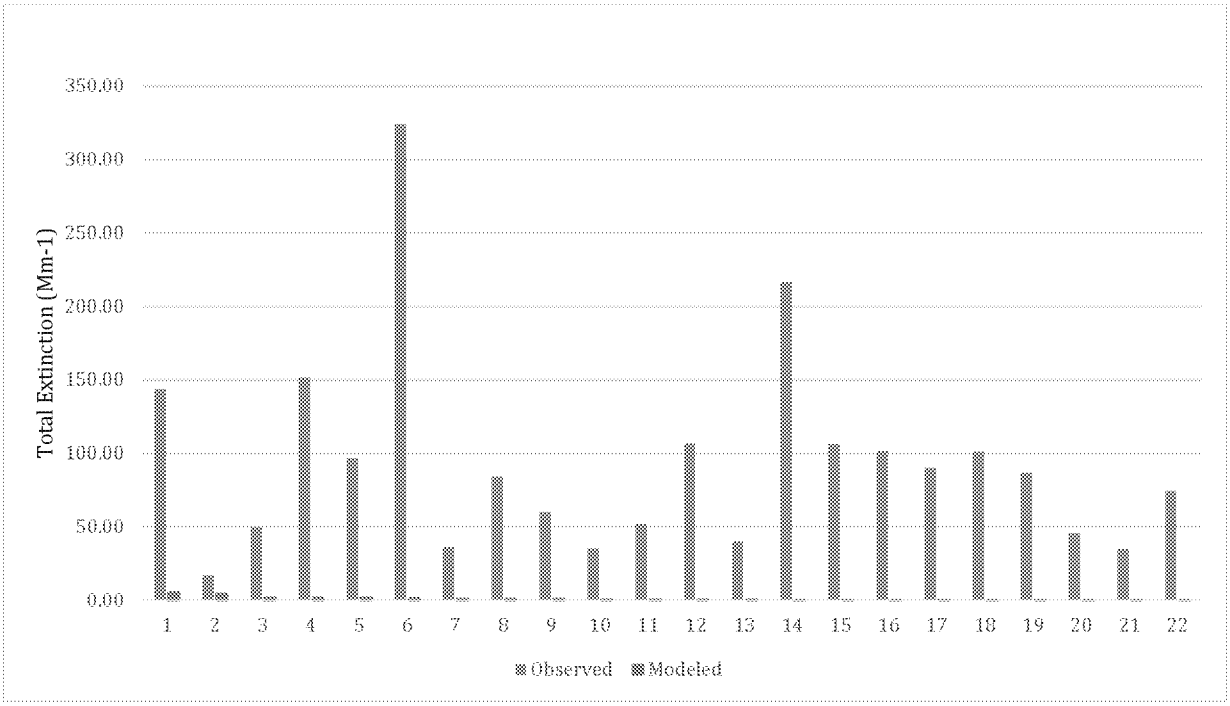
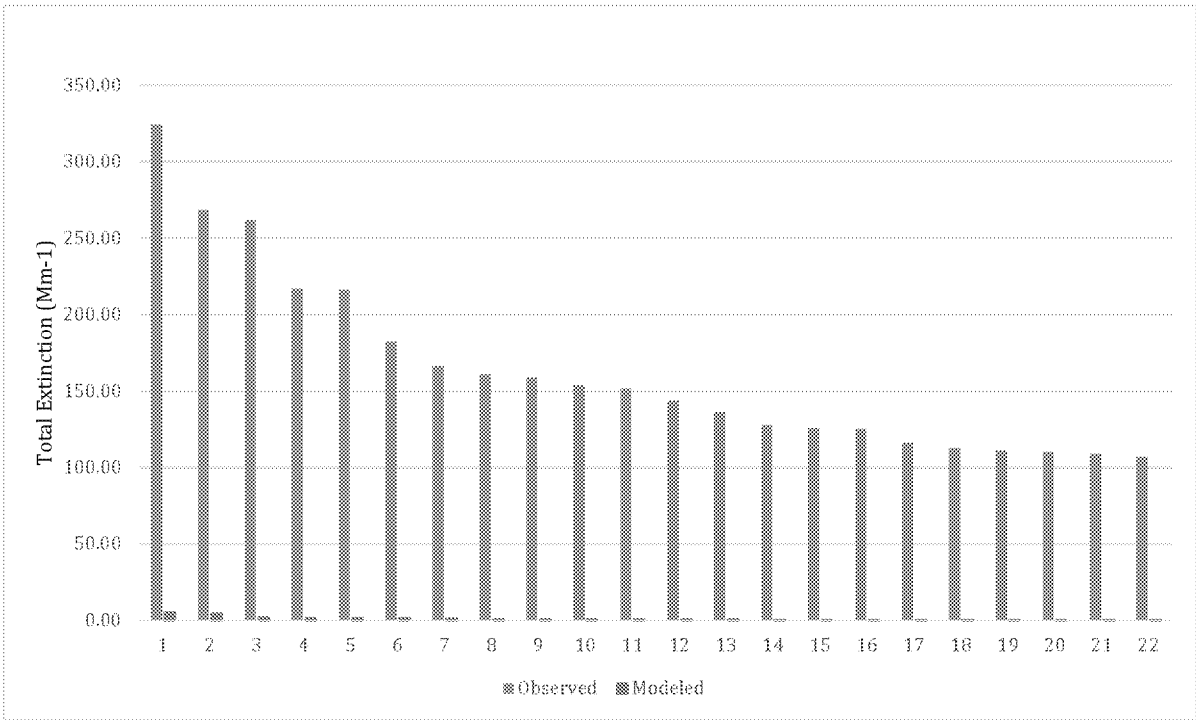


Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART



As demonstrated by the plots above, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine, on the Class I area. This indicates that the contribution from the Lake Catherine Plant to overall visibility impairment at Caney Creek is negligible.

4.1.2. Upper Buffalo Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 for Upper Buffalo.

Figure 4-4. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

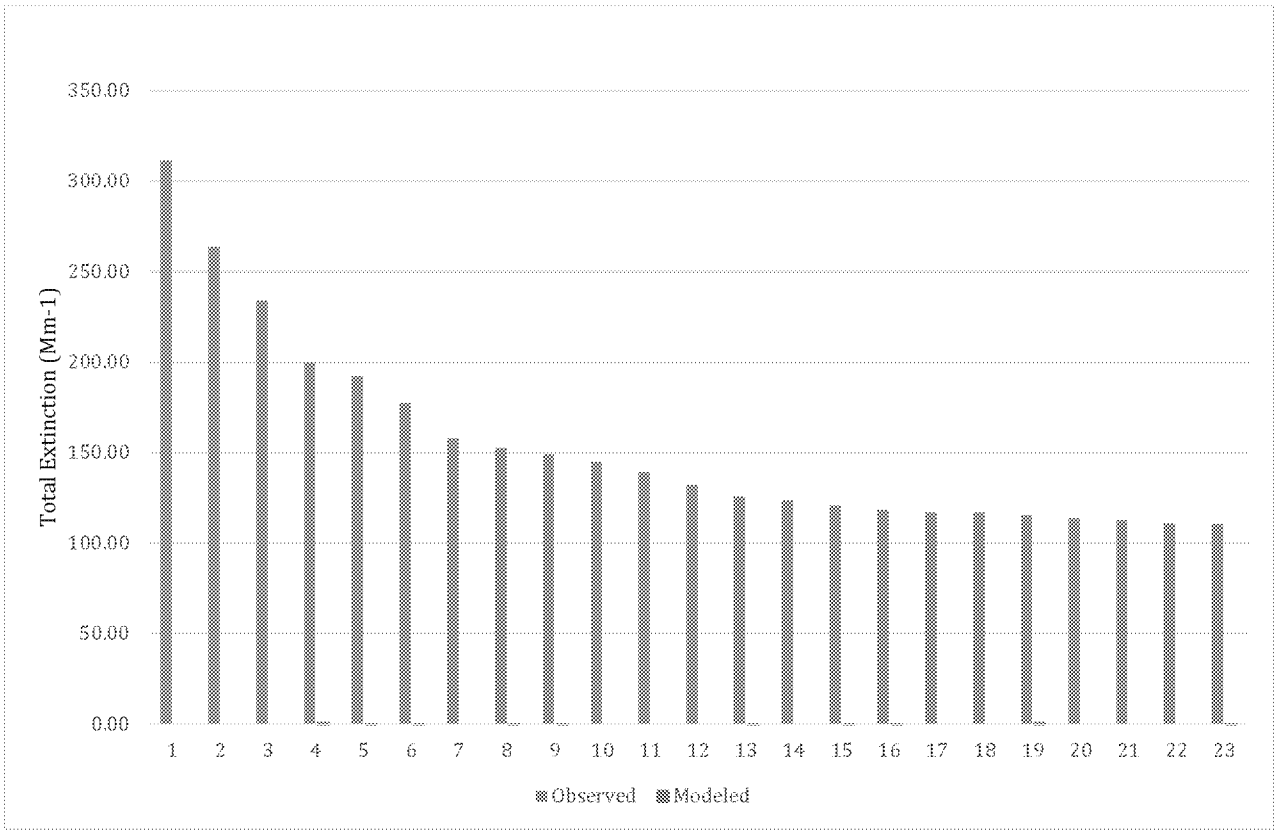


Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

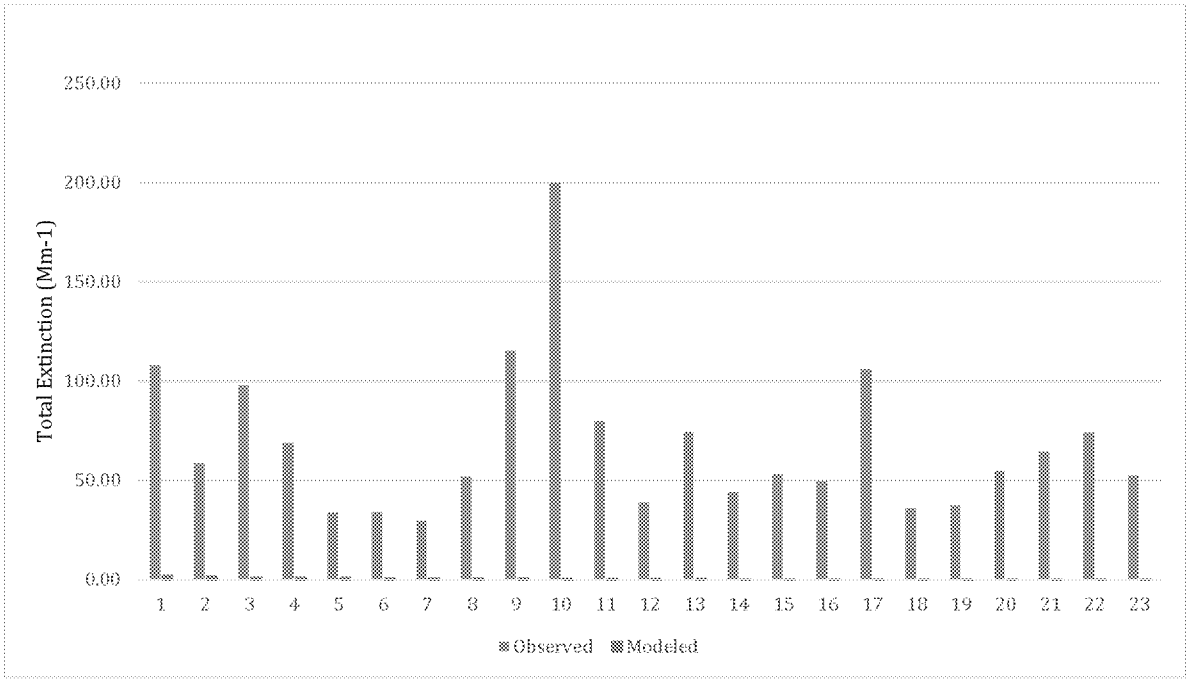
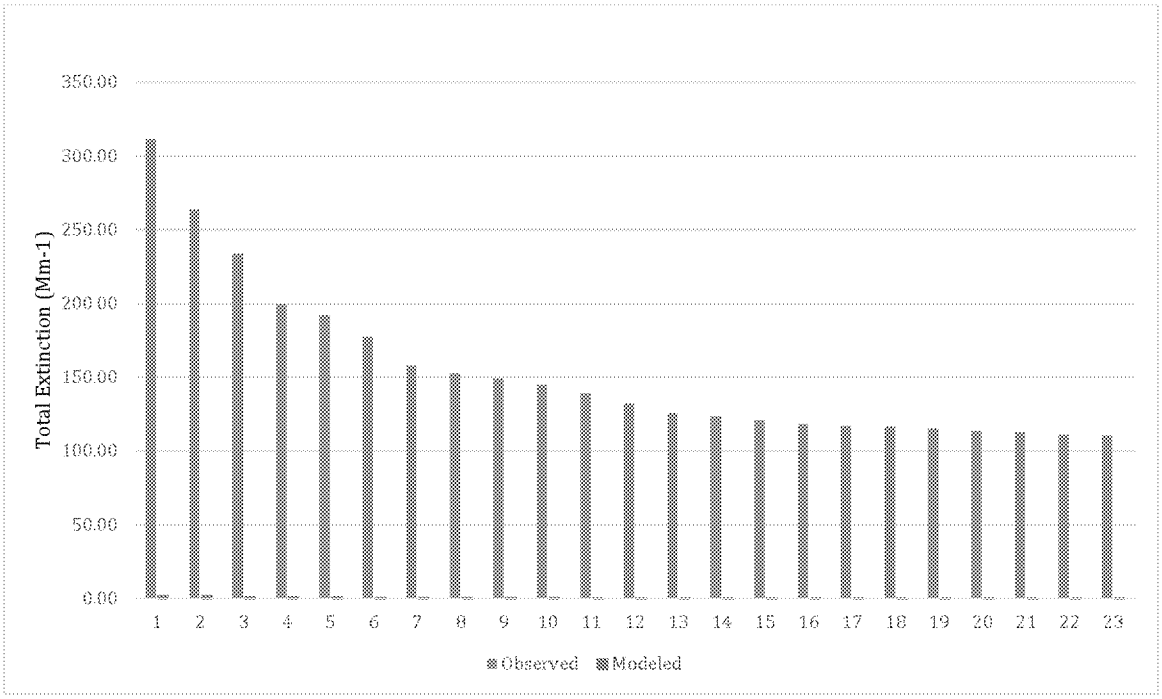


Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART



As was the case for Caney Creek, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine. Thus, the contribution from the Lake Catherine Plant to visibility impairment at Upper Buffalo is negligible.

5. CASE STUDIES

In June of 2012, TRC wrote a paper entitled *Accuracy of Visibility Protocol Modeling in BART Evaluations*.[8] This paper discussed several case studies comparing modeled values from CALPUFF to measured values from the IMPROVE monitoring network. PPL Montana relied on this study in its successful challenge to the Montana FIP, for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[9,10] An overview of several case studies comparing CALPUFF modeled to measured values, including the study relied upon in the Montana Case, are provided below for reference.

The CALPUFF version approved by EPA for use in BART analyses is Version 5.84, which was released on June 23, 2007.[11] Comparisons of modeled to monitored values demonstrate a significant improvement in model performance.

5.1. MOHAVE GENERATING STATION

CALPUFF modeling completed for the Mohave Generating Station (Mohave Station) showed that the 1,590 megawatt (Mw) coal-fired power plant was causing visibility impacts of 2.31 dv at the Grand Canyon National Park. The plant was permanently shut down in 2005. A review of monitored visibility at IMPROVE stations as close as 90 km to the plant showed no change in either nitrate concentrations or visibility impacts subsequent to the closure of the plant. The measured visibility impairment at the Grand Canyon National Park during the three years prior to (2003-2005) and subsequent to the permanent shutdown (2006-2008) of the Mohave Station were analyzed.[12] Based on a review of data from three (3) IMPROVE monitoring sites, summarized in Table 5-1 below, the changes in visibility were not statistically significant.

Table 5-1. Mohave Visibility Impairment – Before and After

IMPROVE Monitor	2003-2005 (dv)	2006-2008 (dv)	Difference (dv)
Meadview	8.24	8.23	0
Indian Gardens	8.92	8.86	0.1
Hance Camp	6.54	6.61	-0.14

While the actual change at the nearest monitor between pre- and post-shutdown of the Mohave Station, Meadview, was zero dv, the CALPUFF results indicated that visibility impairment caused by the Mohave Station

[8] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[9] Montana Case, at 1146–47.

[10] 42 U.S.C. 7491(g)(2).

[11] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012. Although numerous updates have been released since that time, EPA still relies on an outdated version of the model despite the fact that considerable advancements have been made. Newer versions of CALPUFF include more complex chemistry which allows for more accurate representation of sulfate and nitrate formation by considering ozone chemistry, organic aerosol formation, inorganic gas particle equilibrium, and aqueous phase transformation.

[12] Jonathan Terhorst and Mark Berkman, *Effect of Coal-fired Power Generation on Visibility in a Nearby National Park*, Atmospheric Environment 44, 2010.

was twice the level detectable by the human eye.[13] The maximum CALPUFF predicted visibility impairment was 3.94 dv over 3 years, with a 98th percentile visibility impairment of 2.31 dv from the Mohave Station. Based on the IMPROVE monitoring data, CALPUFF highly overestimated the visibility impairment attributable to the Mohave Station. In reality, the Mohave Station had essentially no impact on the visibility impairment at the Grand Canyon National Park as documented by the change in monitoring values pre- and post-shutdown.

5.2. CRAIG STATION

The Craig Station is located approximately 90 km west of the Mt. Zirkel Wilderness Area (Mt. Zirkel) in northwestern Colorado. A study was completed during the development of the Colorado Regional Haze SIP to compare CALPUFF predicted impacts for the Craig Station to IMPROVE data at Mt. Zirkel.[14] Modeled impacts for the Craig Station on the highest 25 days were compared against IMPROVE data, which includes impacts from all other sources (e.g., other point sources, area sources, mobile sources, etc.). The results showed that the modeled impacts from the Craig Station exceeded the monitored values on 14 out of 19 days, and in some instances by a significant amount. Given that the IMPROVE data reflects the cumulative impact of all sources, both within Colorado and outside of the state, the magnitude of the CALPUFF model over-prediction is severe. Although there is another large power plant located between the Craig Station and Mt. Zirkel, the modeled impacts from the Craig Station alone were larger than the monitored values for all sources combined, which further highlights the degree of over prediction. The modeled values were on average ten times the IMPROVE monitored values (i.e., 9.56 Mm^{-1}).[15]

5.3. NORTH DAKOTA SIP

In the development of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDH) relied on photochemical modeling conducted by the Western Regional Air Partnership (WRAP) to determine the impact of sources located outside of the state, as well as non-utility sources in North Dakota.[16] CALPUFF was utilized to determine the impacts of utility sources within the state; however, NDDH utilized alternate options in the CALPUFF model to address known areas of inaccuracy. The specific areas where they deviated from the EPA BART prescribed approach include:

- Consideration of boundary conditions based on CMAQ modeling, rather than ignoring the impact of sources outside of the domain as is done in the EPA approach;
- Puff splitting;
- Diffusion coefficients based on actual measurements of turbulence rather than the 1952 Pasquill-Gifford diffusion confidents required by the EPA approach;
- Meteorological data from the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model; and
- Use of hourly average ammonia concentrations instead of an annual average value.

The resulting CALPUFF values were then compared to IMPROVE monitoring data from the South Unit at Theodore Roosevelt National Park, as summarized in Table 5-2 below.[17]

---

[13] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[14] Gale Hoffnagle, Evaluation of Craig BART Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.

[15] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[16] North Dakota State Implementation Plan, February 24, 2010.

[17] North Dakota State Implementation Plan, Chapter 8, February 24, 2010.

A review of extinction values showed that the average difference between measured and modeled extinction was 0.37 Mm^{-1} with a standard deviation of 12.6 Mm^{-1}.[18] EPA rejected NDDH's modeling on the basis that it included impacts from other sources rather than evaluating the impairment due to BART sources against the natural background visibility impairment ("dirty" background analysis vs. "clean" background analysis). EPA did not specifically comment on the accuracy of NDDH's CALPUFF modeling. Even with the revisions to the modeling methodology applied by NDDH, the margin of error was still 0.39 dv on average.[19]

Table 5-2. NDDH Measured versus Modeled Nitrate Concentrations

Theodore Roosevelt South Unit	Observed (µg/m³)	Predicted (µg/m³)
98th Percentile	2.03	2.06
90th Percentile	1.21	1.21
Average of 20% Worst Days	1.42	1.41
Annual Average	0.53	0.53

5.4. COLSTRIP GENERATING STATION

As briefly described above, TRC conducted an analysis of measured versus modeled visibility impacts for the Colstrip Station located in eastern Montana, which is partially owned and operated by PPL Montana, LLC. TRC specifically completed comparisons for the worst 20% measured days and worst 20% modeled days (where a corresponding measurement was available). The study found that CALPUFF significantly over predicted impacts from the Colstrip Station, as impacts from this source alone were frequently higher than the monitored values, which include all sources (e.g., point, area, mobile) as well as the Colstrip Station. Modeled nitrate extinction from the Colstrip Station alone was higher than the monitored values on 11 out of 22 of the worst 20% modeled days at the Theodore Roosevelt IMPROVE monitoring site. At the UL Bend Wilderness Area IMPROVE monitor, modeled nitrate extinction from the Colstrip Station exceeded the monitored values on 11 out of 28 of the worst 20% modeled days. At the North Absaroka IMPROVE site, the impact from the Colstrip Station was over predicted on 9 out of 20 days of the worst 20% modeled days. At the Yellowstone IMPROVE site there are 10 days when the modeled extinction from the Colstrip Station exceeded the monitored values for the worst 20% modeled days.

Based on this analysis, PPL Montana, LLC, the operator and partial owner, challenged EPA's BART analysis for Colstrip Station arguing that EPA could not "reasonably anticipat[e] as required by the [Clean Air Act]" the maximum predicted visibility improvement for Colstrip Units 1 and 2 because the incremental visibility improvement was within the model's margin of error.[20] The U.S. Court of Appeals for the Ninth Circuit concluded that EPA's response that low levels of visibility impairment must be addressed regardless of whether the visibility improvements are perceptible to the human did not resolve how EPA can reasonably anticipate visibility improvements within a model's margin of error.[21] Given the small magnitude of the CALPUFF predicted visibility improvements for Entergy's Lake Catherine Unit 4, Entergy similarly questioned whether EPA can

[18] These statistics are based on the exclusion of January 26, 2002 which was an outlier.

[19] [19] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[20] Montana Case, at 1146.

[21] *Id.*

reasonably anticipate visibility improvement from additional controls on the Lake Catherine Plant. As such, Trinity utilized a similar methodology to determine the CALPUFF margin of error specifically for the Lake Catherine analysis. Trinity's analysis is summarized in detail within Sections 4 *Modeling Methodology* and 5 *Results* of this report. As documented in the results section, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated* because the visibility improvements are within CALPUFF's margin of error.

6. CONCLUSIONS

Based on the analysis completed for the Entergy Lake Catherine Plant, the minimum calculated margin of error for CALPUFF for the Lake Catherine Plant is 0.93 dv. The CALPUFF predicted visibility improvements associated with EPA's proposed BART for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART cannot be *reasonably anticipated*, as is required by the Clean Air Act.[22]

[22] 42 U.S.C. 7491(g)(2).

Entergy Arkansas Inc.

Comments on the Proposed Approval and Promulgation of Implementation Plans; Arkansas; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility

Docket No. EPA-R06-OAR-2008-0633

Submitted on:
August 5, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov

ENTERGY ARKANSAS INC.

COMMENTS ON THE PROPOSED APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS; ARKANSAS; INTERSTATE TRANSPORT STATE IMPLEMENTATION PLAN TO ADDRESS POLLUTION AFFECTING VISIBILITY

EPA-R06-OAR-2008-0633

I. INTRODUCTION

On July 6, 2015, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 38419, a proposed rule that would disapprove a revision to the State Implementation Plan ("SIP") submitted by the State of Arkansas on September 16, 2009, for the purpose of addressing the requirements of the Clean Air Act ("CAA") regarding interference with other states' programs for visibility protection for the 2006 revised 24-hour fine particulate matter ("$PM_{2.5}$") National Ambient Air Quality Standard ("NAAQS") ("Proposed Rule" or "Proposal"). Section 110(a)(2)(D)(i)(II) of the CAA, which EPA identifies as "Prong 4," requires that SIPs contain provisions to prohibit emissions from within the state from interfering with measures required to be included in the implementation plan for any other state under the visibility protection provisions of Part C of the CAA. EPA has interpreted this "good neighbor" provision as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. 80 Fed. Reg. at 38420. In addition to proposing to disapprove Arkansas' Prong 4 SIP submittal, EPA is proposing that the regional haze Federal Implementation Plan ("FIP") that the Agency proposed on April 8, 2015, *see* 80 Fed. Reg. 18944, remedies the deficiency created by the proposed disapproval of Arkansas' submittal.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA would regulate under the regional haze FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). As proposed, the regional haze FIP would impose Best Available Retrofit Technology ("BART") emission limits on White Bluff Units 1 and 2, the Auxiliary Boiler at White Bluff, and Unit 4 at Lake Catherine, as well as reasonable progress emission limits on Units 1 and 2 at Independence. As a result, EPA's proposal that the proposed regional haze FIP would satisfy Arkansas' Prong 4 obligation directly and significantly impacts Entergy.

In these comments, Entergy discusses its legal concerns with the Proposed Rule. Entergy appreciates EPA's consideration of these comments.

II. COMMENTS

A. Arkansas' SIP Satisfied Prong 4, Rendering Reliance on EPA's Proposed Regional Haze FIP Unnecessary.

EPA argues that Arkansas' SIP submittal fails to satisfy Prong 4 for two reasons. First, although Arkansas indicated in its SIP submittal that it complies with the Prong 4 requirement, it did not explain how it meets the requirement. 80 Fed. Reg. at 38421. Second, in 2012, EPA partially disapproved the SIP revision submitted by Arkansas in 2008 to address the regional haze requirements, including disapproving a large portion of Arkansas' BART determinations. *See* 77 Fed. Reg. 14604 (Mar. 12, 2012). As a result, EPA contends, the corresponding emission reductions from Arkansas sources upon which other states had relied in their regional haze SIPs would not take place. *Id.* EPA therefore proposes that its proposed regional haze FIP is necessary to address the requirement regarding interference with other states' programs for visibility protection for the 2006 $PM_{2.5}$ NAAQS. *Id.* at 38422.

Contrary to EPA's position, the Arkansas SIP submittal satisfies Prong 4, rendering the regional haze FIP unnecessary to address interference with other states' visibility SIPs. First, the SIP submittal does explain how it complies with Prong 4 by specifically identifying the state regulations that ensure emissions from Arkansas sources will not interfere with other states' regional haze SIPs. Second, while EPA has issued guidance documents stating that Prong 4 may be satisfied through the promulgation of a regional haze SIP, this is not the *only* way in which a state may meet its obligation. *See* Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards, at 9-10 (Aug. 15, 2006).[1] Indeed, EPA itself has acknowledged states may satisfy Prong 4 by something other than an EPA-approved regional haze SIP. 76 Fed. Reg. 8326, 8328 (Feb. 14, 2011) (Proposed Approval and Promulgation of State Implementation Plans; State of Colorado; Interstate Transport of Pollution Revisions for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS: "Interference With Visibility" Requirement).

In its SIP submittal, Arkansas indicated that Prong 4 was satisfied by (1) the EPA-approved Arkansas Pollution Control and Ecology Commission's Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Chapter 14; (2) A.C.A. § 8-4-311(a)(2), which authorizes ADEQ to advise, consult, and cooperate with other agencies of the state, political subdivisions, industries, other states, the federal government, and with affected groups to control or abate air pollution and to prevent new air pollution; and (3) A.C.A. § 8-4-311(a)(8), which authorizes ADEQ to represent the state in all matters pertaining to the plans,

---

[1] Guidance issued after submittal of the Arkansas' SIP revision on September 16, 2009, similarly indicates that a regional haze SIP is not the exclusive way in which a state may demonstrate compliance with Prong 4. *See* Guidance on SIP Elements Required Under Sections 110(a)(1) and (2) for the 2006 24-Hour Fine Particle National Ambient Air Quality Standards, at 5-6 (Sep. 25, 2009); Guidance on Infrastructure State Implementation Plan Elements Under Clean Air Act Sections 110(a)(1) and 110(a)(2), at 34 (Sep. 13, 2013) ("A state air agency may elect to satisfy prong 4 by providing, as an alternative to relying on its regional haze SIP alone, a demonstration in its infrastructure SIP submission that emissions within its jurisdiction do not interfere with other air agencies' plans to protect visibility.") ("2013 Guidance").

procedures, or negotiations for interstate compacts in relation to air pollution control. Prong 4 SIP Submittal Attachment at 2.[2] This was sufficient to comply with Prong 4, because it identifies the regulatory mechanisms through which Arkansas works with other states to ensure that its emissions do not interfere with visibility efforts. Arkansas emissions cause and contribute to visibility impairment primarily in two Class I areas in Missouri, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, and potentially other Class I areas in Oklahoma, Kentucky, Illinois and Louisiana. Proposed Approval Regional Haze Interstate Transport SIP, 76 Fed. Reg. 64,186, 64,193, 64,215 (Oct. 17, 2011); Final Approval Regional Haze Interstate Transport SIP, 77 Fed. Reg. 14604, 14623 (Mar. 12, 2012). Of these states, only Missouri relied upon anticipated BART controls from sources in Arkansas when developing its regional haze SIP. *See* Missouri Regional Haze SIP, at 45 (June 25, 2009).[3] Subsequent to EPA's partial disapproval of the Arkansas BART limits, Missouri released a 5-Year Progress Report demonstrating that Mingo and Hercules Glades are on track to meet the 2018 visibility goals. Missouri Regional Haze Plan: 5-Year Progress Report, at 4, 17 (Aug. 29, 2014).[4] Missouri concluded that this progress was the result of emissions reductions at Missouri sources and that further reductions are not necessary. *Id.* at 1, 4, 17. Thus, Missouri has determined that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with Missouri's reasonable progress efforts.

B. EPA's Proposal to Rely on its Proposed FIP Is Premature and Violates the Notice and Comment Requirement.

EPA proposes to find that the requirements of Prong 4 will be satisfied by the combination of the emission control measures in the proposed regional haze FIP, and the already approved portions of the Arkansas regional haze SIP. 80 Fed. Reg. at 38422. It is inappropriate for EPA to propose such a finding when the Agency has not yet finalized its regional haze FIP. As EPA recognizes, the Agency cannot finalize this proposal unless and until it finalizes its action on the regional haze FIP. *See id.* Depending upon the comments submitted to EPA on the proposed FIP, the final regional haze FIP could be substantially different from the proposal. For example, Entergy intends to submit comments on the proposed regional haze FIP objecting to the proposed BART limits for White Bluff and the proposed reasonable progress limits for Independence. Entergy also has identified numerous legal and technical deficiencies in the proposed FIP, which will be discussed in detail in Entergy's comments on the proposed FIP.

It is impossible to know, during the comment period on this rulemaking, whether the final FIP will rectify these problems. Because significant changes could be made to the final FIP, because these changes are unforeseeable, and because Entergy has significant concerns that the final FIP may be legally and technically deficient, it is unreasonable to request public comment on a proposal that the final FIP will satisfy Prong 4. This is a clear violation of EPA's obligation under the Administrative Procedure Act to provide adequate notice and opportunity to comment on a proposed rule. 5 U.S.C. § 553. EPA should defer requesting public comment on this issue until after the Arkansas regional haze FIP has been finalized.

---

[2] Docket ID EPA-R06-OAR-2008-0633-0006.

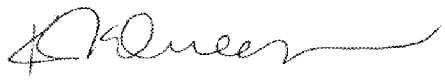
[3] http://dnr.mo.gov/env/apcp/reghaze/moreghaze-09rev.pdf.

[4] http://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf.

III. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed Rule. For the reasons explained in these comments, Entergy strongly urges EPA to approve the Arkansas Prong 4 SIP submittal. In the alternative, Entergy requests that EPA defer issuing a final rule until after (1) the final regional haze FIP for Arkansas has been issued, and (2) EPA has reopened the comment period for this Proposal to allow interested parties to comment on EPA's proposal that the final Arkansas regional haze FIP satisfies Arkansas' Prong 4 requirements.

Respectfully submitted,



Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

These are late comments that were submitted to us outside of the comment period for our proposed rulemaking. These comments are not considered as part of the Administrative Record for our Arkansas Regional Haze and Interstate Visibility Transport FIP rulemaking EPA-R06-OAR-2015-0189.

Entergy Services, Inc.
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel. 501-377-5760
Fax 501-377-5814
kmcque1@entergy.com

Kelly McQueen
Assistant General Counsel

August 8, 2016

Mr. Guy Donaldson
Chief, Air Planning Section (6PD-L)
U.S. Environmental Protection Agency
Region 6
1445 Ross Avenue, Suite 700
Dallas, TX 75202-2733

Re: Request for EPA to Consider and Amend Administrative Record Regarding Material New Information for the Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189

Dear Mr. Donaldson:

Entergy Arkansas Inc. ("EAI") respectfully requests that the U.S. Environmental Protection Agency ("EPA") incorporate into the above docket the attached Supplemental Comments and supporting information regarding EPA's analysis of the best available retrofit technology ("BART") requirements in the final Regional Haze and Interstate Visibility Transport Federal Implementation Plan ("FIP") for Arkansas ("Supplemental Comments"). Although the comment period on the proposed rule has closed, EPA has the authority and discretion to consider the attached Supplemental Comments and supporting information. The material submitted corrects one of the fundamental bases of EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). This information is thus crucial to ensuring that EPA has the most accurate, complete, and timely information, and EAI respectfully requests that EPA consider this information and include it as part of the record.

The Supplemental Comments provide critically important information that (1) became available after the comment period closed, and (2) goes to core issues in the rulemaking.

EPA-HQ-2018-002296

Specifically, the comments provide information on current operations and emissions at the White Bluff Steam Electric Station ("White Bluff"), as well as future projected operations at White Bluff, which necessitate corrections to EAI's October 2013 Five Factor Analysis. Since the date of EAI's Comments on the proposed FIP, dated August 7, 2015 ("EAI Comments"), due largely to market conditions, including lower natural gas prices and dispatch of the White Bluff units through the Midcontinent Independent System Operator ("MISO"), and EAI's ongoing long range resource planning, EAI's assumed remaining useful life ("RUL") of the two coal-fired units at White Bluff has changed.[1]

The Supplemental Comments demonstrate that, based on the adjustment to the RULs, in addition to other changes described in the Supplemental Comments and Exhibit 1 (*Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*), the sulfur dioxide ("SO_2") control technology proposed as BART for White Bluff is economically infeasible/unjustifiable. EAI now projects the RULs to be four and five years from the proposed date of compliance with the FIP, with one unit ceasing coal fired operation at the end of 2025 and the other unit at the end of 2026.

Additionally, Exhibit 2 of the Supplemental Comments includes an evaluation of the most recent monitoring ("IMPROVE") data for the two Arkansas Class I areas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo). This evaluation shows that visibility impairment continues to decline and trend downward at a steeper slope than the uniform rate of progress ("URP") glidepaths for both Class I areas in Arkansas. Additionally, the updated IMPROVE data further confirm that both Caney Creek and Upper Buffalo already have surpassed the reasonable progress goals ("RPGs") that EPA has proposed for these Class I areas. Accordingly, reasonable progress controls during the first planning period are not necessary to achieve the proposed RPGs.

All of the information presented in EAI's Supplemental Comments is relevant and material to EPA's decision making, and must be considered by EPA and be part of the record to ensure full and reasoned decision making based on all pertinent and current facts. Thank you for considering these Supplemental Comments, and we will be happy to answer any follow up questions.

Sincerely,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

[1] The RULs discussed in this letter and the Supplemental Comments are based on an assumption that the FIP will be finalized this year and require SO_2 controls to be installed within five years. *See* EAI Comments at 6.

EPA-HQ-2018-002296

Attachments:

Supplemental Comments of Entergy Arkansas, Inc., including:

- Exhibit 1 – *Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*, Trinity Consultants (Aug. 8, 2016)

- Exhibit 2 – *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016)

cc: Becky Keogh, Director, Arkansas Department of Environmental Quality

ED_002110_00032343-00004

Entergy Arkansas Inc.

Supplemental Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 8, 2016

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

I. INTRODUCTION

During the comment period on the proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas ("Proposed FIP"),[2] Entergy Arkansas Inc. ("EAI") submitted comments addressing the proposed sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") best available retrofit technology ("BART") requirements for the two coal-fired units at the White Bluff Steam Electric Station ("White Bluff").[3] Specifically, for SO_2 BART, EAI submitted comments proposing to end coal-fired usage at the two White Bluff units by the end of 2027 for one unit and by the end of 2028 for the other unit, which limited their remaining useful lives for the purposes of calculating the cost effectiveness of the proposed SO_2 BART control technology. For NOx BART, EAI proposed a compound pound per hour/pound per million btu limitation for the White Bluff units in the event that EPA did not finalize a determination that meeting the Cross State Air Pollution Rule ("CSAPR") in Arkansas was more effective than source-specific NOx BART. EAI proposed a pound per hour limitation due to concerns that the White Bluff units would not be able to meet EPA's proposed NOx BART limit of 0.15 lb NOx/mmBtu at loads of less than 50 percent of capacity. Finally, EAI submitted IMPROVE data demonstrating that visibility is improving at a greater rate than the glidepaths for the two Arkansas Class I areas and that, as a result, reasonable progress controls on Arkansas sources are unnecessary during the first regional haze planning period.

Since the close of the comment period, new information has become available that revises EAI's assumptions for the proposed SO_2 and NOx BART requirements for the White Bluff units. Due to recent market conditions, which EAI expects will continue for the foreseeable future, the White Bluff coal-fired units have been dispatched less and are operating at lower annual average capacity factors. As a result and consistent with EAI's long-range plans, EAI now anticipates that it will cease combusting coal at the White Bluff units by the end of 2026[4], which further limits their remaining useful lives than EAI proposed in its Comments and definitively demonstrates that the cost of SO_2 control technology at White Bluff is not cost effective. Accordingly, EAI requests EPA to determine SO_2 BART for each of the White Bluff coal-fired units to be either a 30-boiler operating day emission rate of 0.06 lb SO_2/mmBtu based on the installation of the previously proposed SO_2 controls or the cessation of operation of the coal-fired units by the end of 2026 as an alternative to the installation of the costly controls, as described more fully below. In addition, EAI has refined its proposed NOx BART emission rate limitation to ensure that the White Bluff units will be able to meet the limitations at lower capacity factors. Finally, more recent Interagency Monitoring of Protected Visual Environments ("IMPROVE") data further support EAI's Comments that reasonable progress controls are unnecessary for visibility improvement at Arkansas' two Class I areas during the first planning

[2] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[3] *See* Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas (Aug. 7, 2015); Docket No. EPA-R06-OAR-2015-0189-0166 ("EAI Comments"). These Supplemental Comments do not waive any argument or issue raised in EAI's Comments.

[4] As outlined in EAI's recent Integrated Resource Plan and consistent with its long-term strategy to diversify its fuel portfolio, this timeline – as opposed to EPA's proposed FIP requirements - would better allow EAI time to replace the units' capacity and develop other supply options including renewables and energy efficiency while continuing to provide reliable service at the lowest cost possible.

EPA-HQ-2018-002296

period. The recent IMPROVE data show that visibility in both Class I areas in Arkansas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo), is already better than both the uniform rate of progress ("URP") goals for the first planning period and the reasonable progress goals ("RPGs") that EPA proposed for the two Class I areas.

EAI's Supplemental Comments and recommended SO_2 and NOx BART determinations address issues on which EPA requested comment during the comment period and support the comments that EAI previously submitted to EPA.[5] Accordingly, it is appropriate that EPA consider these Supplemental Comments before finalizing the Arkansas Regional Haze FIP.

II. COMMENTS

A. Corrections to the October 2013 White Bluff Five Factor Analysis

At the time EAI submitted its Comments on the Proposed FIP, EAI proposed that it would cease burning coal at the two coal-fired units at White Bluff in 2027 and 2028.[6] This changed the calculation of the costs of installing and operating SO_2 control technology on the units due to their limited remaining useful life ("RUL") of six to seven years and demonstrated that EPA's proposed SO2 BART was not feasible.[7] Since that time, there have been notable changes in the market conditions affecting dispatch of the White Bluff units. Specifically, natural gas prices have dropped sharply and are anticipated to continue to remain low.[8] The decline in natural gas prices, coupled with the White Bluff units' dispatch through the Midcontinent Independent System Operator ("MISO"), have significantly decreased the units' annual average capacity factors as compared to their prior historical annual average capacity factors. Figures 1 & 2 below illustrate this change in operation of the units.

---

[5] *See* EAI Comments at Sections III. A, C and E.

[6] *Id.* at 5.

[7] The RULs are based on an assumption that the FIP will be finalized this year and require controls to be installed within five years. *See id.* at 6.

[8] *See Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases*, U.S. Energy Information Administration, at 50 (May 17, 2016), available at https://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf.

ED_002110_00032343-00007

Figure 1. White Bluff Unit 1 Heat Input (MMBtu/yr, 12-month Rolling Values)

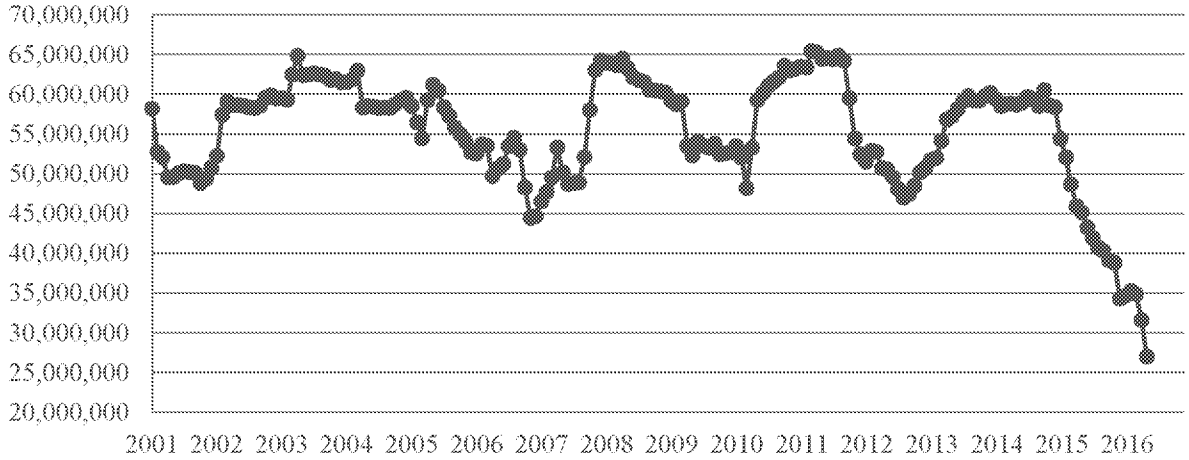
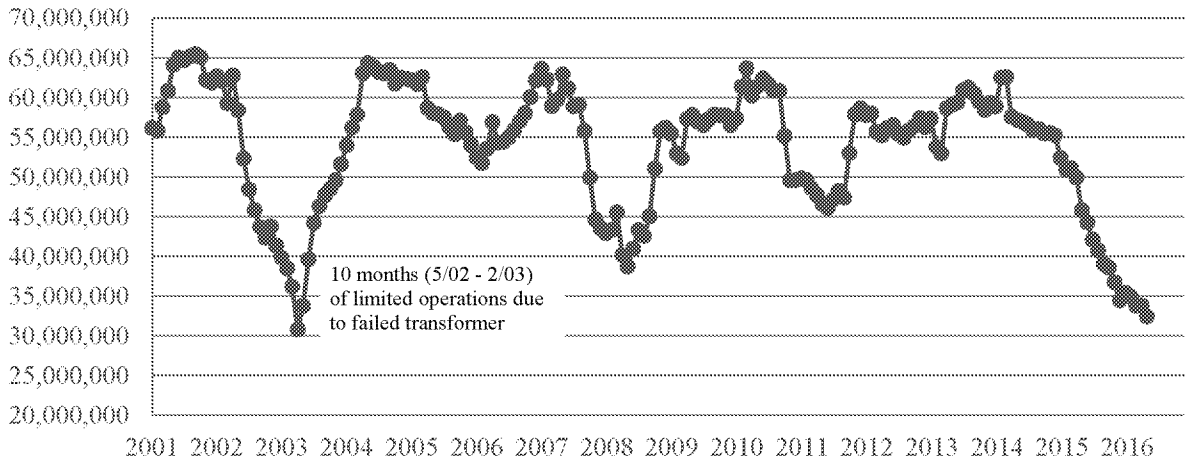


Figure 2. White Bluff Unit 2 Heat Input (MMBtu/yr, 12-month Rolling Values)



Due to the changes in market conditions at White Bluff resulting from the lower natural gas prices and lower dispatch of the White Bluff coal-fired units through MISO and consistent with EAI's ongoing resource planning, EAI has revised its analysis of the continued operation of the White Bluff units and projects that the units will cease combusting coal by the end of 2025 and the end of 2026.[9] This necessitates a change to the amortization period for SO_2 controls, since the units are not anticipated to continue operating beyond 2026. EAI further projects that one of the White Bluff units will operate at a capacity factor of 50 percent or less during 2025.

The limited RULs for the two White Bluff units, coupled with the 50 percent capacity factor operating constraint on one unit in 2025 (hereafter both are referred to as "operation restrictions"), necessitate corrections to EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). Specifically, as

[9] At this time, EAI is unable to make a final determination as to which unit will cease operation first.

discussed further in the attached report prepared by Trinity Consultants, *Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2* (Aug. 8, 2016) (Exhibit 1 to these Supplemental Comments), when the operation restrictions are taken into account for the two White Bluff units, the costs of installing the proposed SO_2 BART control technology, spray dryer absorber ("SDA") technology, is unjustifiable at White Bluff. Based on the detailed cost analysis prepared in 2015 by Sargent & Lundy,[10] the cost effectiveness of SDA would range from approximately $10,400 to $11,800 per ton.[11] Even using EPA's cost projections, which EAI believes ignores significant cost elements of such a project,[12] the costs are in excess of $5,000 per ton.[13] These are unacceptably high cost effectiveness values and cannot be considered BART for the White Bluff units.

Given their short RULs of four or five years, as demonstrated in Exhibit 1, the proposed SO_2 BART controls for the White Bluff units are not cost effective. As a result, SO_2 BART for the units should be *no additional controls*.[14] EAI requests that the final Arkansas regional haze FIP explicitly provide EAI with the option for SO_2 BART of either an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease coal fired operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

B. NOx BART Limit for White Bluff

If EPA does not provide that compliance with CSAPR satisfies the NOx BART requirements for Arkansas' electric generating units,[15] EAI's Comments proposed that the White Bluff units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr, based on the installation of low NOx burners and separated overfire air for all periods of operation and, additionally, a rolling 30-boiler operating day average NOx emission rate of 0.15 lb NOx/mmBtu for unit operation at 50-100 percent of capacity.[16] EAI proposed the pound per hour limit due to concerns that the vendor Entergy selected to supply the NOx control technology would only guarantee EPA's proposed NOx BART rate of 0.15 lb NOx/mmBtu for loads of 50 percent of capacity or greater.[17] Given the updated capacity factor information for the White Bluff units as discussed above in Section II.A, EAI has even greater concerns that the units will be unable to meet EPA's proposed 30-boiler operating day average NOx BART limit of 0.15 lb NOx/mmBtu for significant periods of time.

---

[10] Exhibit B to EAI Comments.

[11] Exhibit 1 at 1-2.

[12] *See* EAI Comments at 8-11.

[13] Exhibit 1 at 3.

[14] EAI continues to propose that, as an interim SO_2 reduction measure, the White Bluff units would take a limit on their permitted SO_2 emission rates of 0.6 lb SO_2/mmBtu on a rolling 30-day average basis beginning three years from the effective date of the final FIP through ceasing operation. This is a 50 percent reduction from their current permitted limits. EAI Comments at 13.

[15] *Id.*

[16] *Id.* at 13-14; 51-52.

[17] *Id.* at 13, n. 16; 51.

EAI continues to request that, if EPA rejects a determination that CSAPR equals BART for Arkansas, EPA should adopt a pound per hour limitation for the White Bluff units when they are operating at a low capacity factor. EAI has refined its analysis of the proposed NOx limitation, however, and now proposes the following limits as NOx BART for each of the White Bluff units:

i. For unit operation at 0-49.9 percent of capacity, a limit of 1,305 lb NOx/hr, based on a 30-boiler operating day rolling average and

ii. For unit operation at 50-100 percent of capacity, a limit of 0.15 lb NOx/mmBtu based on a 30-boiler operating day rolling average to include only those hours for which the unit was dispatched at 50 percent or greater of maximum capacity.

EAI believes the revised rate of 1,305 lb NOx/hr is achievable and appropriate as NOx BART for the White Bluff units for periods when the White Bluff units are operating at a low capacity factor.

C. Most Recent IMPROVE Data

In the EAI Comments, EAI presented IMPROVE monitoring data showing that the haze index has been consistently below the uniform rate of progress ("URP") in both Caney Creek and Upper Buffalo.[18] As a result, reasonable progress controls for the first planning period are unnecessary.[19] This conclusion is bolstered by more recent IMPROVE monitoring data that has become available subsequent to the close of the comment period. As discussed further in Trinity's Report, *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016) (Exhibit 2 to these Supplemental Comments), the IMPROVE data for January 2014 through September 2015 show that visibility continues to improve by a greater amount than the URPs in Caney Creek and Upper Buffalo.[20]

In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas is already better than the RPGs that EPA proposed for the areas. EPA proposed to set the RPG for the 20 percent worst days at 22.27 deciviews ("dv") for Caney Creek and at 22.33 dv for Upper Buffalo.[21] The recent IMPROVE data for both Class I areas demonstrate that the areas already are exceeding the proposed RPGs, as well as Arkansas' RPGs and that visibility impairment is continuing to trend downward.[22]

Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's proposed RPGs for the first planning period, reasonable progress

[18] *Id.* at 20-23.

[19] *See generally, id.* at 17-43 (discussion of why reasonable progress controls are unnecessary at the Independence Steam Electric Station during the first planning period).

[20] Exhibit 2 at 1-3.

[21] 80 Fed. Reg. at 18,997.

[22] Exhibit 2 at 3.

EPA-HQ-2018-002296

controls during the first planning period are *not necessary* to ensure reasonable progress towards the natural visibility goal. *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

III. CONCLUSION

The operation restrictions for the White Bluff coal-fired units and attendant cost information provided in these Supplemental Comments and in Exhibit 1 demonstrate that the BART determination for SO_2 for the White Bluff coal-fired units should be no additional controls. For SO_2 BART, the final Arkansas regional haze FIP should provide EAI with the option for the White Bluff coal-fired units of either meeting an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

Further, the most recent IMPROVE data provided in Exhibit 2 demonstrate that visibility already is better in Arkansas' Class I areas than the URP goals, Arkansas' RPGs or EPA's proposed RPGs for the first planning period. As a result, no additional controls are necessary to make reasonable progress towards reducing visibility impairment at the two Arkansas Class I areas for the first planning period.

The information in these Supplemental Comments and attached Exhibits, which was not available during the comment period on the proposed FIP, is current and highly relevant as it goes to three of the issues at the core of the rulemaking–the SO_2 BART determination for White Bluff, the NOx BART limits for White Bluff, and the need for reasonable progress controls during the first planning period. Accordingly, EAI respectfully requests that EPA include these Supplemental Comments and attached Exhibits in the administrative record for the Proposed FIP and incorporate this information into the Agency's analysis of SO_2 and NOx BART for White Bluff and the reasonable progress requirements for the first regional haze planning period.

ED_002110_00032343-00011

UPDATE TO THE BART FIVE FACTOR ANALYSIS FOR WHITE BLUFF STEAM ELECTRIC STATION UNITS 1 AND 2 REDFIELD, ARKANSAS (AFIN 35-00110)

Prepared By:

TRINITY CONSULTANTS, INC.
5801 E. 41st St., Ste 450
Tulsa, Oklahoma 74135
(918) 622-7111

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77201
(501) 377-4000

Trinity Project No. 163701.0067

August 8, 2016

Entergy.
THE POWER OF PEOPLE®

Trinity Consultants

Exhibit 1 to EAI Supplemental Comments

Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2

This report contains updated control cost calculations for the SO_2 and NO_X BART Five Factor Analyses for White Bluff Units 1 and 2 (SN-01 and SN-02). The update is necessary to consider new information regarding the remaining useful life ("RUL") of the units,[1] which affects the capital recovery period for the proposed BART controls, i.e., for SO_2 control, Spray Dryer Absorber technology ("SDA"). This new information was not available when the *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* was submitted on October 15, 2013.

EAI anticipates one of the two coal-fired units will cease operating in 2025 and the other unit in 2026. Based on FIP promulgation in 2016 and a five-year compliance timeline, this means that whichever unit ceases operations in 2025 would have an RUL of four (4) years and the other unit would have an RUL of five (5) years. Additionally, one of the units will operate at a capacity factor (CF) of no greater than 50 percent in the year 2025. Together, the RULs and CF limitation are referred to herein as "the operation restrictions".

Updated SO_2 Control Costs

The update to consider the operation restrictions results in average cost effectiveness values for SDA of between approximately $10,400 and $11,800 per ton of SO_2 removed depending on which of the two units has an RUL of four years and which has an RUL of five years. This entire range of average cost effectiveness is infeasible as BART.

The updated emissions and cost effectiveness calculations for SDA based on the operation restrictions are presented in Table 1 and Table 2 for Unit 1 and Unit 2, respectively. The emissions information and capital and O&M cost estimates are based on Sargent & Lundy's 2015 report.[2] Using instead the emissions information and capital and O&M cost estimates from EPA's proposed FIP Technical Support Document, Appendix A, the average cost effectiveness estimates for SDA are between approximately $5,000 and $5,900 per ton of SO_2 removed. Summaries of these estimates are shown in Tables 3 and 4. Even these unrealistic and artificially low cost values are also economically infeasible.

[1] Remaining useful life is one of five factors to be considered in the BART impact analysis. The other four factors are cost of compliance, energy impacts, non-air quality environmental impacts, and visibility improvement.
[2] Sargent & Lundy LLC, *Entergy Arkansas, Inc. - White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831 (July 2015)(Exhibit B to EAI's Comments on the proposed FIP).

Table 1. SDA Cost Effectiveness - White Bluff Unit 1

Baseline Emission Rate (tpy)	15,939	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,675	
Emissions Reduction (tpy) [1]	14,264	13,414
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,560,422
Total Annual Costs ($/yr)	168,462,888	140,330,954
Cost Effectiveness ($/ton)	11,810	10,461

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 2. SDA Cost Effectiveness - White Bluff Unit 2

Baseline Emission Rate (tpy)	16,034	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,681	
Emissions Reduction (tpy) [1]	14,353	13,490
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,555,003
Total Annual Costs ($/yr)	168,462,888	140,325,535
Cost Effectiveness ($/ton)	11,737	10,402

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 3. SDA Cost Effectiveness - White Bluff Unit 1 ***Using FIP Information***

Baseline Emission Rate (tpy)	15,816	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,453	
Emissions Reduction (tpy) [1]	14,363	13,534
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,335,696
Total Annual Costs ($/yr)	85,109,693	71,707,739
Cost Effectiveness ($/ton)	5,926	5,298

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 4. SDA Cost Effectiveness - White Bluff Unit 2 ***Using FIP Information***

Baseline Emission Rate (tpy)	16,697	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,476	
Emissions Reduction (tpy) [1]	15,221	14,266
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,275,230
Total Annual Costs ($/yr)	85,109,693	71,647,273
Cost Effectiveness ($/ton)	5,592	5,022

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Updated NO_X Control Costs

Consideration of the operation restrictions results in NO_X control cost effectiveness estimate changes as summarized in Table 5. The proposed BART control technology remains LNB+SOFA as presented in the October 15, 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* at the emission rates presented in EAI's August 8, 2016, supplemental comments.

Table 5. NOx Controls Cost Effectiveness

	Baseline Emission Rate	Controlled Emission Level	Controlled Emission Rate[1]	NOx Reduced	NOx Reduced for 5-Year RUL[2]	Capital Cost	Annualized Capital Cost, 4-year RUL	Annualized Capital Cost, 5-year RUL	Annual O&M Cost, 4-year RUL	Annual O&M Cost, 5-year RUL[3]	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(lb/MMBtu)	(tpy)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
SN-01 LNB/SOFA	7,249	0.15	4,145	3,104	2,919	10,461,206	3,088,442	2,551,391	319,887	300,831	2,852,222 - 3,408,329	977 - 1,098	
SN-01 LNB/SOFA/SNCR	7,249	0.13	3,592	3,657	3,439	21,371,325	6,309,416	5,212,267	4,849,000	4,560,150	9,772,417 - 11,158,416	2,842 - 3,051	13,314 - 14,022
SN-01 LNB/SOFA/SCR	7,249	0.055	1,520	5,729	5,388	230,329,138	67,999,638	56,175,134	3,444,000	3,238,844	59,413,978 - 71,443,638	11,027 - 12,470	22,910 - 29,087
SN-02 LNB/SOFA	8,185	0.15	4,060	4,125	3,877	14,488,206	4,277,326	3,533,539	312,838	294,036	3,827,575 - 4,590,164	987 - 1,113	
SN-02 LNB/SOFA/SNCR	8,185	0.13	3,519	4,666	4,386	25,398,325	7,498,300	6,194,415	4,853,000	4,561,325	10,755,740 - 12,351,300	2,452 - 2,647	13,615 - 14,336
SN-02 LNB/SOFA/SCR	8,185	0.055	1,489	6,697	6,294	206,747,898	61,037,793	50,423,889	3,466,000	3,257,686	53,681,575 - 64,503,793	8,529 - 9,632	20,626 - 25,688

[1] The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

[2] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emission emissions reduction adjustment.

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

Prepared By:

TRINITY CONSULTANTS, INC.
5801 E. 41st St. Ste. 450
Tulsa, Oklahoma 74135
(918) 622-7111

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77201
(501) 377-4000

Trinity Project No. 163701.0059

August 8, 2016

Entergy.
THE POWER OF PEOPLE®

Trinity Consultants

Exhibit 2 to EAI Supplemental Comments

Assessment of Recent Class I Area IMPROVE Monitoring Data

Since the August 7, 2015 submittal of Trinity Consultant's *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (Trinity's report), measured concentration data for January 2014 through September 2015 from the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network of Class I area monitors has become available. It is prudent to review this data for the two Arkansas Class I areas – Caney Creek ("CACR") and Upper Buffalo ("UPBU") – to determine if the trends identified in Trinity's report continue.

A summary of all available haze index values – from 2002 through 2015 (average of first nine months) – are shown in the following tables. As explained in Trinity's report, the IMPROVE equation is applied to the concentration data to calculate light extinction (Mm^{-1}), and then light extinction is converted to haze index (dv).

Table 1. Haze Indices for Caney Creek

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	27.21	11.88
2003	26.54	10.74
2004	25.34	11.11
2005	29.21	12.93
2006	25.68	12.51
2008	23.70	9.24
2009	22.68	8.09
2010	22.94	10.76
2011	22.67	11.71
2012	21.49	9.54
2013	21.35	8.61
2014	20.72	8.52
2015	20.67	8.35

Table 2. Haze Indices for Upper Buffalo

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	26.74	12.83
2003	27.22	10.62
2004	25.58	10.74
2005	30.47	13.34
2006	25.42	13.00
2007	26.17	12.45
2008	24.60	10.49
2009	22.62	9.40
2011	23.21	11.51
2012	21.56	10.31
2013	21.25	8.60
2014	20.49	8.13
2015	20.45	7.81

The following figures illustrate how these measured values compare to the Uniform Rate of Progress ("URP") curves for each area. The figures are updates to Figures 3-3 and 3-4 of Trinity's report, and, as such, also show the projected haze index values based on the scenario-specific modeling summarized in Trinity's report.

Figure 1. Caney Creek Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index

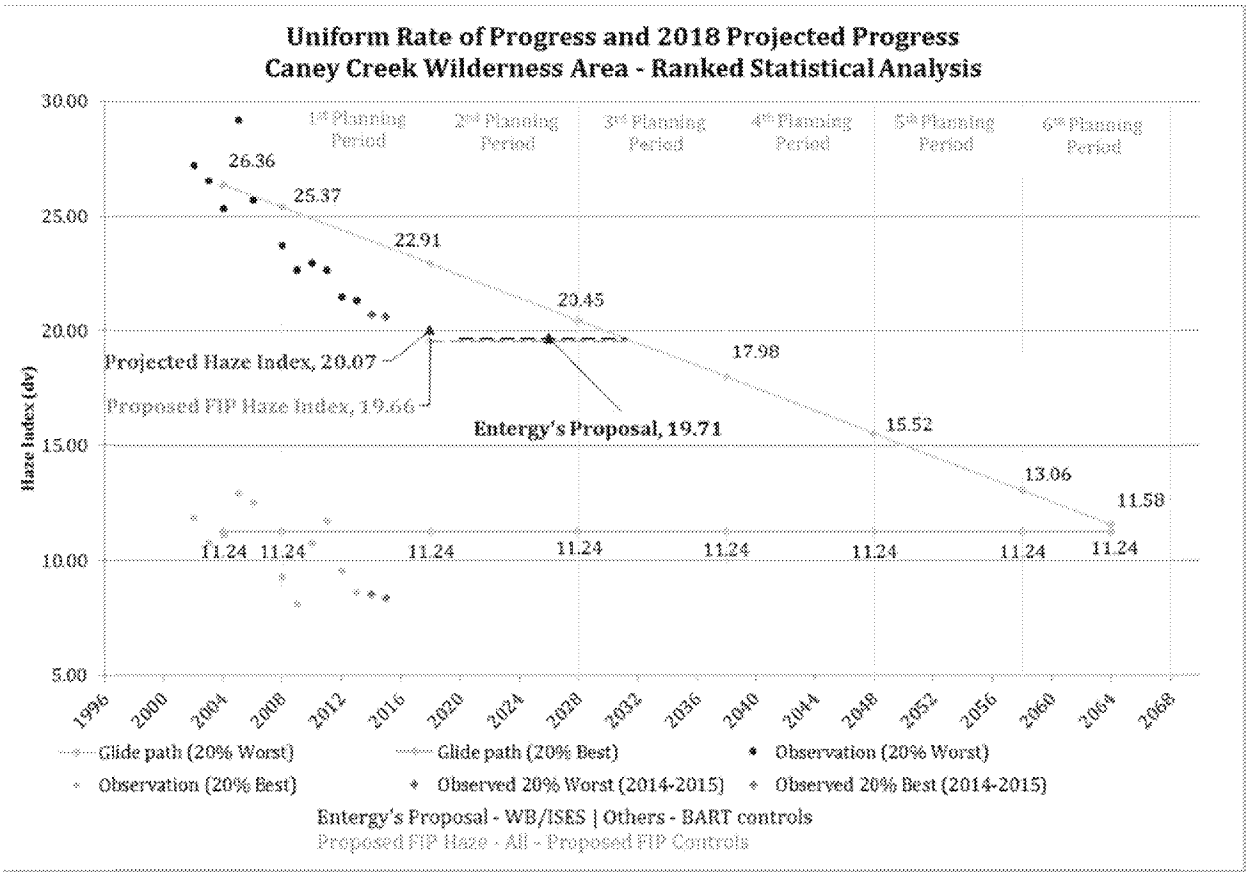
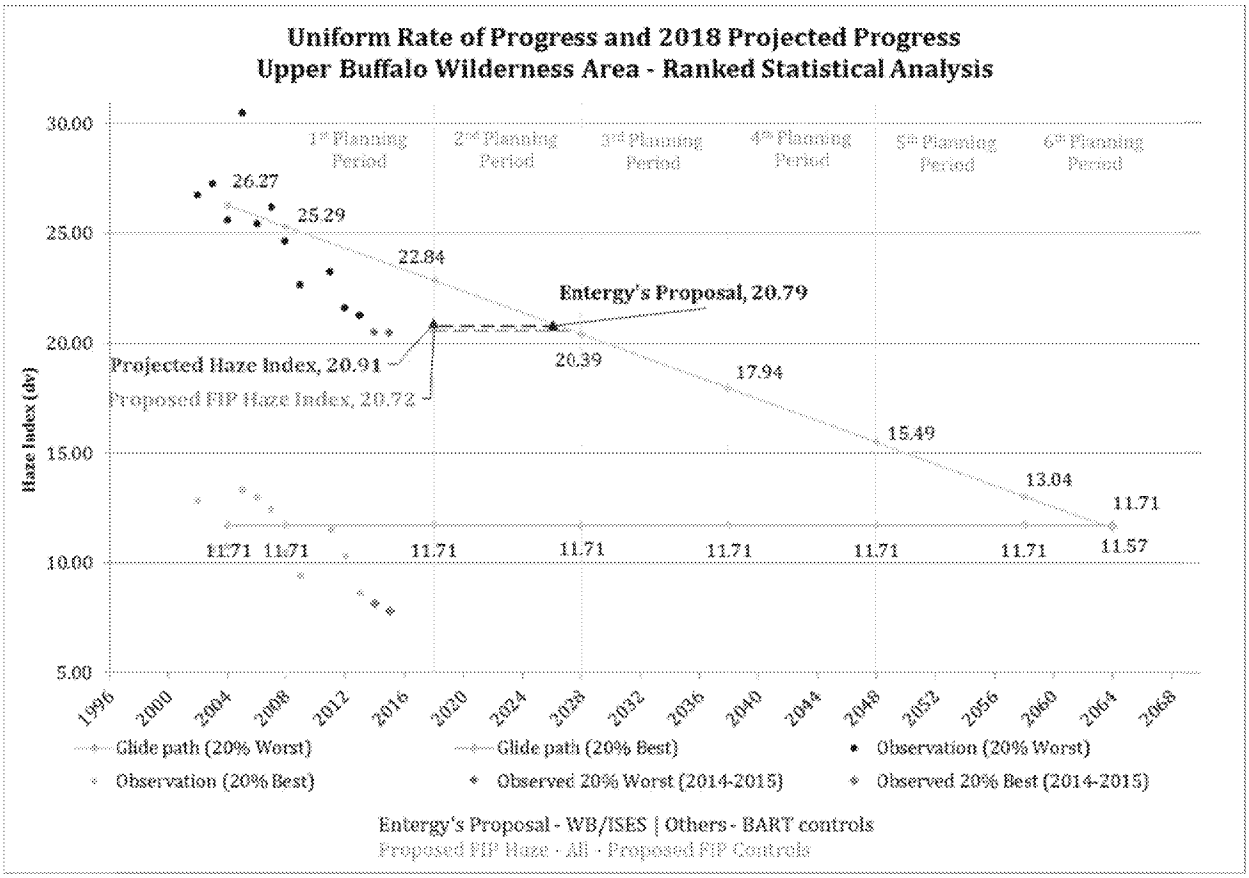


Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



As shown above, the actual visibility impairment at CACR and UPBU have continued to decrease through September 2015. The average 20 percent worst haze indices for CACR decreased from 21.49 dv in 2012 to 20.67 in 2015. Similarly, visibility improved at UPBU, where the average 20 percent worst haze indices decreased from 21.56 dv in 2012 to 20.45 dv in 2015. As shown in the figures and table below, these values are significantly less than (i.e., better than), and ahead of schedule of, the Reasonable Progress Goals (RPGs) proposed by ADEQ[1] of 22.48 dv by 2018 for the 20 percent worst days at CACR and 22.52 dv by 2018 for the 20 percent worst days at UPBU, and those proposed by EPA[2] of 22.27 dv for CACR and 22.33 dv for UPBU.

Table 3. 2018 Reasonable Progress Goals Compared to 2015 Visibility for the 20 % Worst Days

Class I Area	ADEQ-Proposed RPG for 2018 (dv)	EPA-Proposed RPG for 2018 (dv)	Actual Visibility in 2015 (dv)
Caney Creek	22.48	22.27	20.67
Upper Buffalo	22.52	22.33	20.45

[1] Arkansas's 2008 Regional Haze State Implementation Plan (SIP).
[2] April 18, 2015 proposed Arkansas Regional Haze Federal Implementation Plan (FIP).

Figure 3. Caney Creek Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

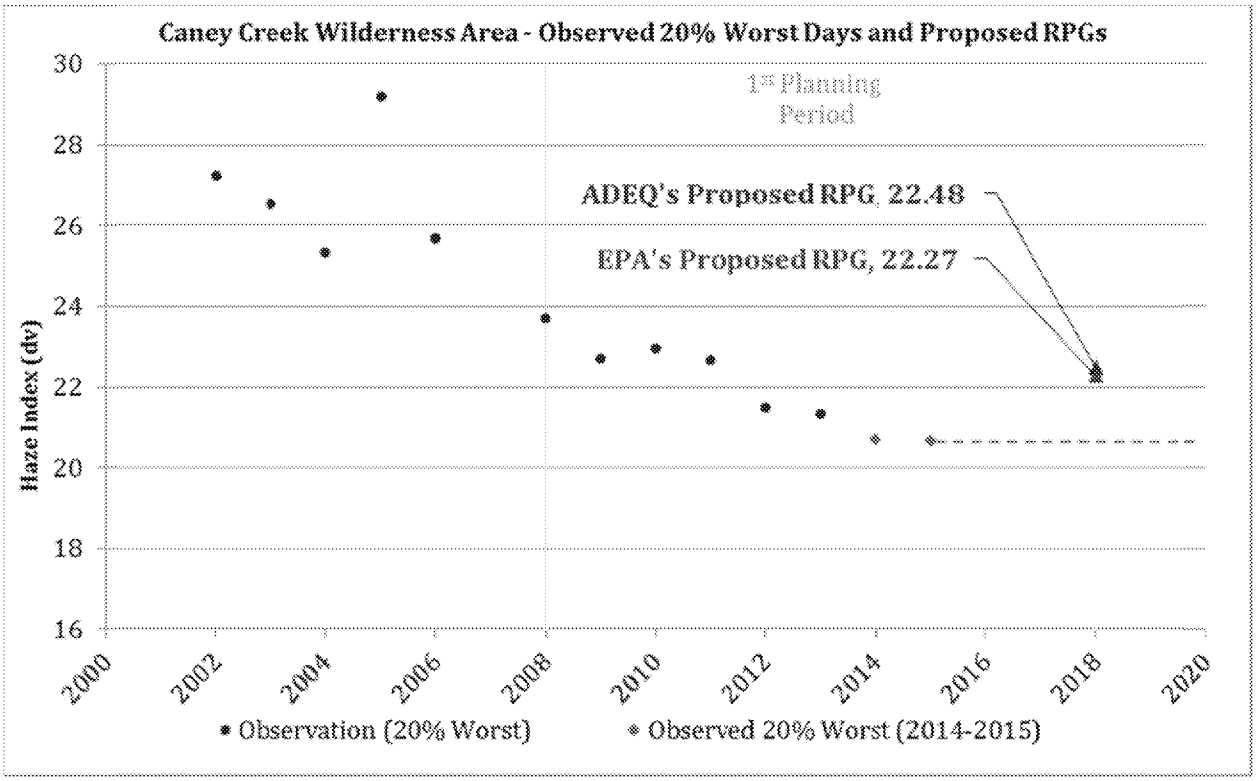
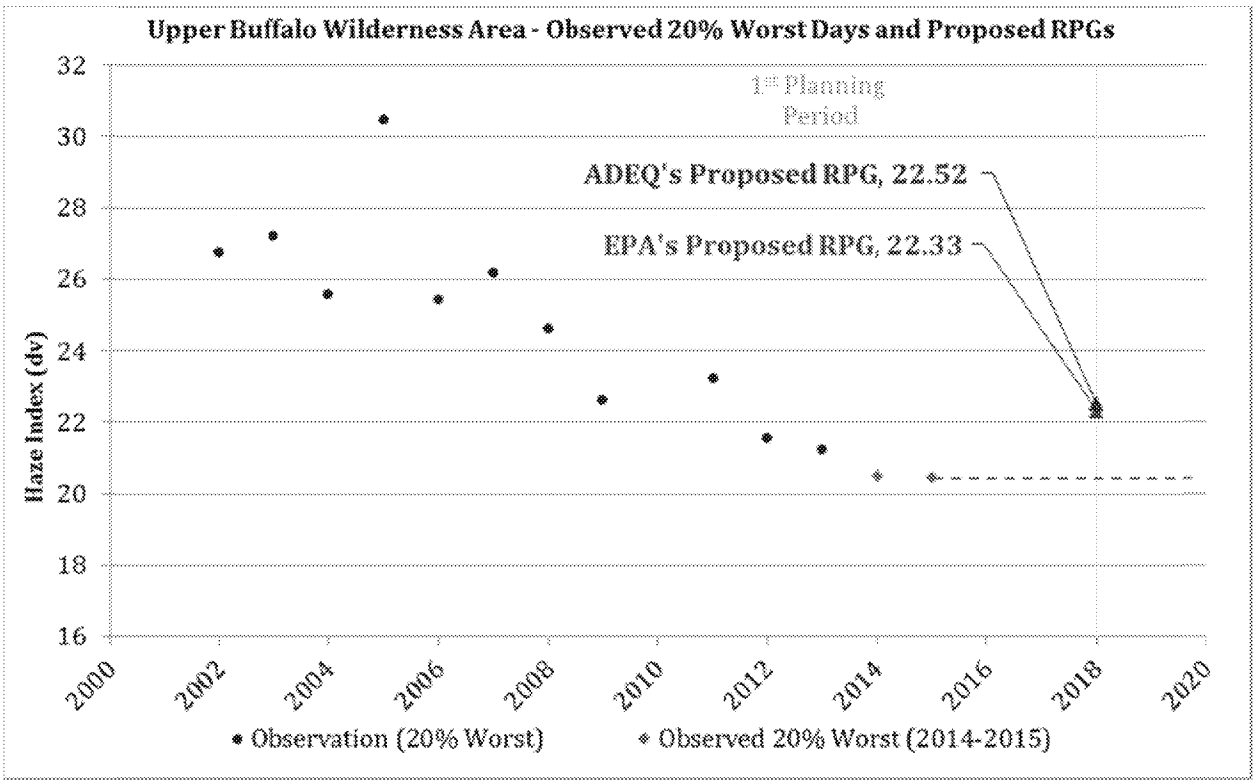


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals



Message

From: Case, Cheryl (Defra) [cheryl.case@DEFRA.GSI.GOV.UK]
Sent: 10/6/2017 12:27:27 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Alex.Doyle@fco.gov.uk
Subject: Visiting Washington between 17th and 20th October

Hi Mandy,
How are you? It seems a lifetime away now since the G7 negotiations and the successful agreement of a communique on Environmental issues. From seeing the press I suspect things have been as full-on with you in the USA as they have been here in the UK since then.
I have good news however that I have finally been able to confirm my first trip to the USA between the 17th and 20th October, and am looking forward to seeing Washington.

The team are putting in place a busy meeting schedule for me around the meetings I am due to have with the World bank on our project funding and with your colleagues in State on Illegal Wildlife Trade (you may have seen the UK Consultation launch today to close the UK Ivory market except for a few limited exemptions).
Apologies for the very short notice but if you are in Washington that week it would be great to catch-up and touch base on the discussions the Administrator and my Minister started at the G7. I understand that the visit that Administrator Pruitt was hoping to have with my Secretary of State will unlikely be possible now this year so I hoped to be able to discuss the policies in this area in order to update my Ministers on my return. If you are able to meet could you suggest a couple of options so that I can get the team to make this work?
Apologies again for the late notice but hoping that you may be available to meet
Kind regards
Cheryl

Dr Cheryl Case
Deputy Director, Head of International
Department for Environment, Food and Rural Affairs
Direct line: +44(0)20 802 62888 | Mobile: +44(0)7799 656 118
Email: cheryl.case@defra.gsi.gov.uk
Area 1E, Nobel House, 17 Smith Square, London, SW1P 3JR.

Department for Environment, Food and Rural Affairs (Defra)

This email and any attachments is intended for the named recipient only. If you have received it in error you have no authority to use, disclose,
store or copy any of its contents and you should destroy it and inform the sender.
Whilst this email and associated attachments will have been checked for known viruses whilst within Defra systems we can accept no responsibility once it has left our systems.
Communications on Defra's computer systems may be monitored and/or recorded to secure the effective operation of the system and for other lawful purposes.

THE BRICK INDUSTRY ASSOCIATION

September 28, 2017

The Honorable E. Scott Pruitt, Administrator
U.S. Environmental Protection Agency
Room 3000
William Jefferson Clinton Building
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Review of Denial of Petition for Administrative Reconsideration of the NESHAP for Brick and Structural Clay Products Manufacturing

Dear Administrator Pruitt:

The Brick Industry Association ("BIA") respectfully requests that the U.S. Environmental Protection Agency ("EPA" or "Agency") review its prior denial of BIA's petition for administrative reconsideration of the National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing, published at 80 Fed. Reg. 65470 (Oct. 26, 2015) ("Final Rule").

Founded in 1934, BIA represents the U.S. clay brick industry, which includes hundreds of manufacturers, distributors, and suppliers that provide employment over 88,000 people. BIA members manufacture over 80 percent of all the brick shipped in North America, and over 75 percent of brick manufacturers are small businesses.

As we have previously stated, we appreciate the time and effort that EPA invested in this rule and believe that it goes a long way toward achieving environmental control without significant and unwarranted costs on affected brick plants. BIA identified, however, issues in the Final Rule that threaten the economic viability of many plants and businesses in our industry. We believe that these issues can be resolved without significantly diminishing the effectiveness of the Final Rule.

BIA timely filed its petition on December 23, 2015. EPA denied BIA's petition in a letter dated May 12, 2016 and issued a Federal Register notice of its denial on few days later. 81 Fed. Reg. 31,234 (May 18, 2016). BIA filed a petition for judicial review of EPA's denial on June 9, 2016, which was ultimately consolidated with petitions for review of the Final Rule.

BIA's petition outlined issues of central relevance in the Final Rule where it was impracticable for BIA to raise an objection during the period of public comment or the grounds for BIA's objection arose after the public comment period. The objections BIA raised are still relevant and valid. BIA respectfully requests that EPA review its prior denial of BIA's petition.

130 Iowa Lane Suite 103 Cary, North Carolina 27511 | Phone: 919-380-2191 | Mobile: 919-924-1185 | www.gobrick.com

Thank you for your consideration of these important issues. We are ready and willing to work with you to resolve these issues. Please feel free to contact Susan Miller at (919) 380-2191 if you have questions or need more information.

Sincerely,

Susan Miller
Vice President
Environment, Health & Safety
Brick Industry Association

cc: M. Gunasekara, OA
P. Tsirigotis, OAQPS
K. Barnett, OAQPS
B. Storey, OAQPS

Message

From: PATERSON, Owen [owen.paterson.mp@parliament.uk]
Sent: 10/9/2017 10:57:16 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Speeches and a note of thanks
Attachments: 041017 CEI Final.pdf; 051017 Washington Brexit speech - Final.pdf

Dear Mandy,

It was great to meet you in Washington last week. We had an interesting discussion and I am grateful to you for taking the time to meet me.

I attach copies of the speeches that I gave to the Competitive Enterprise Institute and to the Heritage Foundation last week, which I hope you will find of interest.

Do of course keep in touch.

Best wishes,
Owen

UK Parliament Disclaimer: This e-mail is confidential to the intended recipient. If you have received it in error, please notify the sender and delete it from your system. Any unauthorised use, disclosure, or copying is not permitted. This e-mail has been checked for viruses, but no liability is accepted for any damage caused by any virus transmitted by this e-mail. This e-mail address is not secure, is not encrypted and should not be used for sensitive data.

Brexit: Good for the UK, good for the USA and good for the planet

The Rt Hon Owen Paterson MP

Competitive Enterprise Institute
Washington, D.C., USA

4 October 2017

Introduction

It is a great pleasure to be here at the Competitive Enterprise Institute and I am grateful to Myron for the invitation to outline the current trends and outlook in British environmental and technological policy. Most of all, I want to discuss the fantastic opportunity which Brexit presents – both to the UK and to our allies – for the return of sane, evidence-based, environmentally-tailored thinking. The EU's environmental approach – and its attitude towards innovation more widely – has stifled progress at the expense of both the consumer and the planet. Brexit, in allowing the UK the chance to break free of this wrong-headed, statist, anti-science thinking, cannot come soon enough.

Happily, on 23rd June 2016, 17.4 million people in Britain voted to leave the European Union, more than have ever voted for any issue or political party in our history. The 72% turnout was the highest since 1992.

Article 50 was triggered on 29th March with the automatic legal effect that at midnight on 29th March 2019, the EU treaties in their entirety will cease to apply to the UK.

In June this year, we had a General Election in which 85% of the votes cast were for parties advocating leaving the Single Market, the Customs Union and the remit of the European Court of Justice. The main "Remain" Party – the Liberal Democrats – saw its number of votes fall.

The European Union (Withdrawal) Bill will repeal the European Communities Act 1972, which gave effect to European law in the UK. It converts into UK law the entire corpus of European law. On the 11th September, it passed its vital second-reading stage in the House of Commons with a clear majority of 36.

Most recently, in her speech in Florence on 22nd September, the Prime Minister again confirmed that our objectives remain unchanged.

These, then, are the facts. Brexit is going to happen, and environmental policy stands to be one of the principle beneficiaries. The EU has single-mindedly pursued an overly-

prescriptive interpretation of the "Precautionary Principle", smothering opportunities for innovation in thrall to the emotions of vocal activists rather than scientific evidence and advice.

The Green Blob dominates thinking in Brussels, with generous grants given to green groups so that they will lobby it for regulations which then require large budgets to enforce.

When I was Secretary of State, I participated in an Environment Council called by Lithuania as the incoming Presidency, to discuss European policy on fracking. So serious was the meeting that only elected Ministers were allowed in with all civil servants excluded. Yet to my surprise, we found a senior representative from the European Environment Bureau, representing 140 green organisations, speaking on equal terms with us. Towards the end of the meeting he gave us an emotive lecture about the dangers of shale gas exploitation. Some of my colleagues from Eastern Europe, for whom energy security is an existential question and who had just come out of decades of undemocratic rule, were absolutely infuriated.

After Brexit, we will be free of these Green Establishment camarillas and free to co-operate with our allies in driving innovation forward.

Global co-operation, local implementation

By its very nature, environmental policy must be global in scope, and it has been organised as such since long before the EU came into existence. In 1972 – the year before the UK joined the EEC – 152 experts from 58 countries attended the first United Nations meeting on the environment, in Stockholm. We were a founding nation of the 1979 Berne Convention on the Conservation of European Wildlife and Habitats, and early signatories to both the Washington Treaty, establishing the Convention on International Trades in Endangered Species, and the Ramsar Convention for protecting wetlands.

Leaving the EU means that the UK can retake a full seat on the world bodies that determine global regulation, at which we are currently represented as 1/28th of the collective EU vote. These include the WTO, the World Organisation for Animal Health, the Codex Alimentarius Commission, which regulates guidelines on food and food safety, and the International Plant Protection Council.

Retaking these seats will not only see us regain our right to vote in such bodies, but also our right to initiate new standards and propose amendments to existing ones. We will, once again, be free to co-operate with long-standing Allies across the Anglosphere and the Commonwealth. We are thus well placed to give global leadership to ensure a viable and sustainable environmental future.

Global co-operation on environmental matters is essential, but the fundamental flaw in the EU approach has been conflating co-operation with uniformity of implementation. Global rules must be interpreted at a national and even a local level so that they best meet the needs of the local environment. It is absurd to seek to apply the same rules across vastly different terrains and eco-systems. There are real lessons to be learnt from the significant powers which each of your 50 states deploy.

The weight of history supports this view. Democracies have a far better record of preserving the natural environment than do unelected governments of whatever shape. Examples abound of the failures of tyrannies and bureaucracies, from the drying up of the Aral Sea in central Asia as a result of Soviet irrigation policy — described by former UN Secretary General Ban Ki-Moon as "one of the planet's worst environmental disasters" — to the catastrophic consequences of the European Union's Common Fisheries Policy, which sees fishermen discarding a million tonnes of otherwise healthy fish every year.

Our departure means that, rather than being tied to a common and often wholly unsuitable European policy, we are free to introduce, amend and strengthen our own legislation conforming to international conventions. We can now do so in response to the needs of our own species and habitats.

We will, for example, remain committed signatories to the Berne Convention, but will be able to direct our efforts to the wildlife actually at risk in the UK, rather than to a notional pan-European list.

Perhaps the best example of the inadequacy of a uniform policy applied from Brussels comes from the Great Crested Newt. Each year, over 1,000 licences are issued to keep these newts out of development sites, costing businesses dearly and stopping desperately needed homes from being built. One developer was forced to spend over $1 million in 2014 to catch 150 of the animals.

Such measures might be thought necessary were Great Crested Newts endangered in this country, but they can be found throughout England, and across much of Scotland and Wales. It is estimated that there are around 75,000 populations in the UK. They are, however, scarce on the continent, so because the UK has a disproportionally large percentage of European newts, many UK developers find themselves unable to build.

Worse still for the environment, the newt fences required can damage ground-nesting birds at nesting times, but a remotely-issued directive takes no account of this. Our new policy will be informed by the best local knowledge, focusing on the interests and priorities of the environment it serves, rather than on targets set hundreds of miles away.

The British Overseas Territory of South Georgia provides a fine example of the success of a local approach. The Islands have been able to take decisive action in arresting and

eradicating its most damaging invasive species. Rats, reindeer and various alien plant species have been eliminated, ushering in renewed growth in the numbers of fur seals, elephant seals, king penguins and a host of other indigenous species.

After Brexit, British environmental policy can see a return to this adaptive approach. The UK will remain happily bound to international conventions — we were, after all, instrumental in shaping many of them – but we will be free to interpret and control them locally.

Control of our borders

Similarly, we will use taking back control of our borders to better protect our native fauna and flora. Damage from invasive species costs an estimated $2.4 billion each year. The red squirrel and the white-clawed crayfish face local and perhaps national extinction in Britain as a result of diseases spread by the signal crayfish and the alien grey squirrel, mistakenly introduced from America in the 19th century. The intransigence of the EU has meant that, while studies have been completed, effective action has been woefully slow, and the threat to these native species continues to grow.

An invasive flatworm from Brazil – the unfortunately-named Obama Flatworm, *Obama nungara* – is a predator of land snails and earthworms, and thus endangers both soil fertility and wildlife. It is already a threat to agriculture in France and is spreading rapidly across Europe. There are 18 further invasive flatworm species already in Europe, and the uncontrolled trade in pot plants is rapidly expanding their reach. Some have a yet worse reputation for environmental harm, with the New Guinea flatworm currently in France recognised among "the 100 worst invasive alien species in the world" by the conservation charity Buglife.

Such groups frequently report the arrival of exotic grasshoppers, wasps, beetles, moths and spiders at garden centres and nurseries, many with the potential to cause dramatic damage to native wildlife and agriculture, only to be met with inaction. Increases in global trading have increased the risks of plant disease, and the insistence of the EU on free movement has increased the rate of ash dieback, and put some 80 million ash trees in the UK at risk.

It is small wonder that the CEO of Buglife, Matt Shardlow, describes our current biosecurity as "feeble". The British Isles being islands, however, gives the UK in co-operation with the Republic of Ireland an enormous natural advantage in protecting our landscape from invasive species. With the latest developments in technology and technique, we can capitalise on that advantage to develop a modern, responsive system to predict, monitor, and control the spread of pests and disease. We can implement a quarantine system with the kind of rigour found in Australia and New Zealand and ensure that the UK becomes a haven for animals, birds, plants and trees for generations to come.

Marine policy

As well as controlling our borders, we will regain full control of our waters and our Exclusive Economic Zone. The EU's Common Fisheries Policy has been a biological, environmental, economic and social disaster. It is a system that has forced fishermen to throw back more fish dead into the sea than they have landed. It has caused substantial degradation of the marine environment. It has destroyed much of the fishing industry. It has devastated fishing communities.

12 years ago, I wrote a Green Paper on the future of British fishing policy, travelling all over the North Atlantic and learning a great deal from the approaches of other nations, particularly in regard to their uptake of technology and selective gear, which I saw at Manomet in Massachusetts.

The most crucial aspect of our new, independent policy must be to take measures to prevent discarding. An EU discard ban has been attempted, but has proven unworkable as it simply banned the symptom, without addressing it as being the inevitable cause of the fixed quotas which the CFP demands.

The fixed-quota system is simply unsuitable for our mixed fisheries, and must be converted to one based upon effort control, which prioritises accurate and timely data collection. The system which most effectively achieves this is also known as "Days at Sea", allocating a fisherman a fixed time to fish in a particular area, requiring him to land everything he catches, with the latest technology carefully managing and tracking data in real time.

Such information is vital for the success of an effort control system, and technological advances make provision for the rapid temporary closure of fisheries in response to risks of excessive commercial catches. Imposing mandatory reporting of all landings further ensures that data collection is as accurate and up-to-date as possible. Thus, Days at Sea is a system which works in tune with nature, and is the only applicable system for the UK's rich mixed fisheries. Technical improvements have made the enforcement of such a system much more effective.

The Fisheries Minister in the Faroe Islands, where it is mandatory to land everything, summarised the pragmatism of the approach by saying: "We might not like what we find, but we know exactly what is going on." In contrast, the EU fisheries policy is based on information which is guaranteed to be inaccurate by at least 50%, and often six months out of date.

International relations with specific partners can be managed through the North East Atlantic Fisheries Commission (NEAFC) of which the Russian Federation, Norway, Iceland, Denmark (representing the Faroe Islands and Greenland) and the European Union are parties. The UK taking up a full seat on the NEAFC will be a huge gain for the environment.

The Precautionary Principle vs The Innovation Principle

That the European attitude to fishing technology lags behind the rest of the world is no surprise. It has also obstinately refused to embrace innovation in agriculture, and is fast being outstripped by economies around the world. It sits on some of the most fertile land on the planet and yet still imports food from the equivalent of 35 million hectares of someone else's farmland.

China, South Korea and North America are vying for global innovation leadership and the rate of change is ever accelerating. The intensity of development in these economies is twice what it is in Europe, which was once the innovation leader. The European devotion to the severest interpretation of the Precautionary Principle, which considers only the environmental hazards of innovation and not its benefits, is turning the continent into the Museum of World Farming.

This over-cautious, intransigent approach is typified by the EU's ban on the use of neonicotinoid insecticides, ostensibly to stem a decline in the honeybee population. This might seem a reasonable response, but for the fact that, quite simply, the honeybee population has not been in decline. In Europe and North America, honeybee numbers are higher today than they were two decades ago when neonics were first introduced. The same is true for wild bees. The observed declines before 1990 ceased or were reversed around the time when neonics were first introduced.

When the ban was first imposed, the EU cited the work of the French scientist Mickaël Henry. M. Henry now confesses that he may have overdosed the bees with neonics in his experiments, as many of us suspected at the time, and admits he has "no real clues" how much insecticide bees encounter in the field.

As a result, the European Commission now concedes that the neonics ban "was at no time based on a direct link on bee mortality." Which raises the questions: Why were neonics banned in the first place and why does the ban still stand?

Though green groups claim that neonics devastate bee populations, there remains much scientific debate over how much neonic residue gets into the pollen that bees consume. The fact remains that there has been no "bee-pocalypse." The reality is that the policy was more influenced by the hysteria of non-governmental organisations and their baseless predictions than a sober analysis of the science. As a result, an increase in insect pests has led to crop losses in fields across Britain and Europe. The canola area planted in Britain for this year was 557,000 hectares, representing a thirteen-year low and continuing a decline which has issued since the ban. In 2016, British farmers lost around $25 million and almost 28,800 hectares of crops due to the ban.

The UK can now do away with the prescriptive EU approach, balancing its Precautionary Principle with the "Innovation Principle", which runs:

"The principle requires that whenever any policy or regulatory decisions are under consideration, the impact on innovation should be fully assessed and addressed."

Thus, both the risks and benefits of any proposed new technology would have to be weighed against the risks and harms of existing technology. It would ensure that policy makers had to consider the potential of new innovations rather than simply strike them down, and force them to assess whether any regulation was likely to stifle progress. It would stimulate confidence, free producers to drive up their productivity and encourage investors in innovation to the UK for the long term.

It is an appalling indictment of the EU regime's extreme technological risk aversion that the world's largest chemical company, BASF, has abandoned all further biotechnology research for the European market. Their entire blight-resistant potato project has moved to the USA, which was terrible news for a constituent of mine who rang me to say that he had sprayed his potato crop 15 times that season, and that developing GM blight-resistant potatoes was the only solution.

GMOs: a case in point

Nowhere is their open hostility towards technology more apparent than in the European attitude towards genetically modified crops. Viewed from any kind of rational standpoint, the current developments in genetically-modified organism (GMO) technology are merely the natural development of the kind of husbandry that mankind has been practising for millennia. We have reached a position in which, as the author Henry Miller noted, "virtually everything in North American and European diets has been genetically improved in some way."

Indeed, the precision of GMOs makes them inherently safe, with a single gene, or several specific genes able to be transferred from one plant into another with precision; unwanted characteristics are incredibly unlikely to make their way into a GM plant, but there are no such guarantees from random breeding. Every step in the creation of a GMO is closely monitored. Here, the Environmental Protection Agency, Food and Drug Administration, and Department of Agriculture require safety tests on every GMO crop before it comes anywhere near the dinner plate.

The results speak for themselves. Quite apart from the potential health benefits that GMOs can bring – eliminating allergens, guarding against contamination for mycotoxins and so on – the simple fact that from the three trillion meals served containing biotech crops in the last 17 years, the World Health Organisation confirms that nobody has ever made a credible claim of adverse reaction.

The potential for GMOs – safely and precisely – to alleviate food scarcity is vast. At present, various types of malnutrition affect almost 2 billion people around the world.

It accounts for the loss of 3 million young lives each year and stunts the growth of one in four children. If we cannot feed ourselves properly now, then how can we expect to do so with our present practices when the global population reaches 9.8 billion in 2050?

The answer is to keep up the pressure to continue the Green Revolution started by Norman Borlaug. I can remember as a child seeing traumatic news bulletins with images of starving people on the Indian subcontinent. Borlaug, put an end to this shame. He is now known as "The man who saved a billion lives" and was awarded the Nobel Peace Prize for his pioneering work in transferring wheat with new genetics from the Americas to the Indian subcontinent in the 1960s. He used genetic modification to save a billion lives from starvation, and now India is a net food exporter.

When I visited South Africa in 2014, I saw at first hand the benefits that GM corn had brought the local smallholders. Production had soared from 1 tonne per hectare using conventional seeds to 5 tonnes per hectare with the GM seed. The crop which they harvest can withstand droughts and destructive pests, ensuring the farmers an income and spurring development still further. Once they had improved their irrigation, farmers expected see an increase to 10 tonnes per hectare.

Yet still, the hostility persists, and nowhere more virulently than in Greenpeace's war on Golden Rice. It was developed at the end of the last century by Professors Ingo Potrykus and Peter Beyer, and is enriched with vitamin A-producing beta-carotene. In 2001, they donated their invention to the world in the hopes that it would be used to end the scourge of vitamin A deficiency, which is the principal cause of childhood blindness globally.

Had Golden Rice been a part of their diet, millions of young eyes and millions of young lives, primarily in Africa and South Asia, would have been saved. The Golden Rice Humanitarian Board lays the blame for their crop's delayed development firmly with political suspicion and interference. Greenpeace, with its $500 million war chest, has rallied the forces of green privilege in a global campaign to frighten the public about GMOs and to pressure governments into keeping Golden Rice off the market.

The Humanitarian Board believe that their project should have been where it is today, with the major part of a regulatory package finished, in around 2006, 11 years ago. There are now fewer deaths among children under five than there were 10 years ago, down to 16,000 per day from 26,000 per day. But they estimate that this death toll still equates to around 4,500 preventable vitamin A deficiency related child deaths daily, and many of them in countries where rice is the staple, usually grown close to where it is consumed.

It is small wonder that 126 Nobel Laureates denounced the Greenpeace campaign against Golden Rice in 2016, saying "Opposition based on emotion and dogma

contradicted by data must be stopped." and asking "How many poor people in the world must die before we consider this a "crime against humanity"?"

It has been estimated that by embracing such technology, less land will be needed, by an area larger than India, to feed the 9.8 billion people of 2050 than is presently required to feed today's 7 billion. Indoor vertical farming based on hydroponics may accelerate the rate of change yet further.

In sharp and frustrating contrast, Europe's reluctance to adopt the latest innovations in agriculture diminishes potential yield and uses up more land than is needed.

US corn yields have overtaken those of France in the last 20 years. When I made this point in 2015, French yields were around 0.9 tonnes/hectare behind American yields. Now, France is missing out on over 3.5 tonnes per hectare compared to the US, amounting to a total loss of 5.6 million tonnes across its 1.5 million hectares. If France had kept pace with US technology, that crop could be worth an extra $800 million to French agriculture, or else France could free up 500,000 hectares currently used for the corn crop and put it to use for wildlife, recreation, or forestry.

Conclusions

Leaving the European Union thus gives the United Kingdom a chance to rid ourselves of its stifling, backward-looking approach to technology. We shall return to the world stage committed to innovation, eager to co-operate with our friends – the United States chief among them – and receptive to the lessons which we can learn from across the world.

When I spoke at Cornell to a conference of agricultural scientists from the developing world in 2015, they saw the possible exit of the UK from the EU as allowing us to rejoin them in the forefront of advanced research, akin to Sleeping Beauty reawakening after 40 years.

New technologies must be embraced, and feasible new developments must be assessed rationally and soberly. For too long, the EU has sought to pre-empt and pick technological winners or, worse still, have set their faces against new technology on the grounds of little more than ill-informed sentiment and prejudice.

A rational, approach, based always on the best available scientific evidence, allowing the invisible hand of a liberalised market to grasp and elevate the technologies most likely to be beneficial in practice, is the surest means of delivering stable, sustainable and — most crucially — affordable policies well into the future.

A newly-independent UK looks forward to taking a leading role with the United States in developing and advancing those new technologies.

Why Brexit is great for the UK and the USA

The Rt Hon Owen Paterson MP

The Heritage Foundation
Washington, D.C.

5 October 2017

Introduction

It is a great pleasure to return to Heritage and I would like to thank Nile for the opportunity to outline the progress on Brexit and the great advantages a newly-independent UK will bring to the long term Special Relationship between our two countries.

There is no greater place to make the case for an outward-looking, independent country than in the capital of one which "stands, one Nation under God, indivisible, with liberty and justice for all." As your Declaration of Independence has it: "When in the course of human events, it becomes necessary for one people to dissolve the political bands which have connected them with another…a decent respect to the opinions of mankind requires that they should declare the causes which impel them to the separation." It is a great pleasure to be able to declare those causes and elucidate those principles once again.

Of course, the US staged its own Brexit in 1776 and there are clear similarities between America's fight for independence and Britain's desire for control over our own affairs, only this time with fewer bayonets and muskets.

The American Revolution and the 2016 Brexit vote had democratic control at their hearts; everyone is familiar with the rallying cry of "No taxation without representation." As with the EU today, American dissatisfaction with British rule was as a result of our overreach in the colonies. It went too far and America declared that enough was enough. You wanted decide how to spend your own money – not be told to send it off to Great Britain.

On 23rd June 2016, 17.4 million people in Britain voted to leave the European Union, more than have ever voted for any issue or political party in our history. The 72% turnout was the highest since 1992.

Article 50 was triggered on 29th March, after 494 Members of Parliament voted for it in the House of Commons. The automatic legal effect of this is that at midnight on 29th March 2019, the EU treaties in their entirety will cease to apply, with no post-exit Treaty obligations on the UK.

In June this year, we had a General Election in which 85% of the votes cast were for parties advocating leaving the Single Market, the Customs Union and the remit of the European Court of Justice. The main "Remain" Party – the Liberal Democrats – saw its number of votes fall.

The opposition Labour Party's position has vacillated to the point of absurdity since the election, but the Conservative Government's position has not changed. Not a single Conservative MP voted against the Queen's Speech this summer, which set out the Government's plans for this Parliament and focused on regaining control of our laws, money and borders.

The European Union (Withdrawal) Bill will repeal the European Communities Act 1972, which gave effect to European law in the UK. It converts into UK law the acquis communautaire, the entire corpus of European law. On the 11th September, it passed its vital second-reading stage in the House of Commons with a clear majority of 36 without a single Conservative voting against, 7 Labour MPs voting for it, and 14 abstaining.

Most recently, in her speech in Florence on 22nd September, the Prime Minister again confirmed that our objectives remain unchanged.

We are building on the precedent which Americans set even before independence – first adopting British law in order for it to be altered subsequently. The Reception Statute passed in the Colony of Virginia in 1776 ran:

"…the common law of England, all statutes or acts of Parliament made in aid of the common law prior to the fourth year of the reign of King James the first…shall be considered as in full force, until the same shall be altered by the legislative power of this colony."

Delaware, New York, Pennsylvania and other states adopted very similar Reception Statutes.

The fact is that Brexit is going to happen, and it will be great for both the UK and the USA.

Despite these decisive steps, there are still those – President of the European Commission Monsieur Juncker among them – who believe that we will back down, or that the process can be derailed. This is unsurprising from a man who, before the French were asked to ratify the proposed European Constitution in 2005, said "If it's a Yes, we will say 'on we go', and if it's a No we will say 'we continue'."

He was true to his word. The French failed to ratify the Constitution, so it was simply reheated as the Treaty of Lisbon and on the project went. When the Danes and the Irish had the presumption to vote against the EU consensus, they were told to go away and vote again until they produced the right answer.

However, we will leave. For the first time in EU history, a country will not be cowed into rerunning a democratic vote whose verdict went against the Commission and the long-term European Project.

And this project is not static. The Five Presidents' Report of 2015 proposed fiscal, economic and finally full political union by 2025. Without the restraint of the British pebble in the shoe, Juncker, in his "State of the Union" address on 13th September 2017 was proposing consolidation and compulsory membership of the Eurozone and by 2025 a fully-fledged European Defence Union. He called for a single European president and the use of passerelle clauses allowing the Commission to bypass the concerns and wishes of democratic national governments.

So I have absolutely no regrets that I was one of 3 founding MPs of the referendum campaign group "Vote Leave". Our central message was that we must "take back control" – of our laws, our money, and our borders.

- To control our own laws, we must end the jurisdiction of the European Court of Justice and leave the Single Market
- To control our money, we will cease sending $11 billion net to the EU each year
- To control our borders, we must leave the Single Market
- To control our trade policy, we must leave the Customs Union

These simple statements, which resonated with 17.4 million people, are not negative ones. They are not anti-Europe. They are positive expressions of the age-old truth that a sovereign country will be more successful when it governs its own affairs.

Single Market

Membership of the Single Market requires acceptance of the indivisible European principle of the Four Freedoms – the free movement of goods, services, capital and, most contentiously of all, people; it requires regulation of all aspects of our economy.

Leaving the Single Market – which is simply the internal market of the EU – is a prerequisite for expanding our trade around the world, because we are, in the main, a services economy and any services negotiation is a negotiation on domestic regulation, which we must control.

In 1999, 61% of UK trade was with the EU, now it is 43%. By 2025, it has been projected that our exports to the EU will account for under 35%. The European Commission itself says that 90% of global economic growth in the next 10 to 15 years is expected to be generated outside Europe, a third of it in China alone.

Compare that to the relationship between our two countries. The USA is the UK's largest export partner and our second-largest import partner for trade in goods and services. In 2015, the USA accounted for 19.7% of the UK's exports and 11.1% of imports. The USA and UK are the largest single investors in each other's countries, at 24.5% and 23.6% respectively.

Only around 12% of the UK's GDP is directly accounted for by exports to the EU. Our dependence on European exports is even lower, as a proportion of our goods sent, in particular, to the continental ports of Antwerp and Rotterdam, are counted as EU exports but are in reality transshipped outside the EU. The economist Roger Bootle has suggested that the proportion of UK GDP not involved in European exports may be as high as 90%.

There is, nonetheless, a clear incentive to continue our trade with the rest of Europe. About 44% of UK exports in goods and services went to other countries in the EU in 2016. We have no desire – and it is in no one's interest – to abandon our close ties. Our goal is, and always has been, reciprocal free trade without tariffs.

The idea that one can trade with Europe only through membership of the Single Market is plainly nonsense. Being within the Single Market means meeting all of its regulatory standards. This sort of compliance is required on export product standards for all exporters wishing to sell in any foreign market. The difference with the European Single Market, however, is that those regulations are applied across the whole economy, even to sectors with absolutely no connection to European exports. This burdensome and invasive bureaucracy is a long way from the original vision of a group of sovereign states sharing a minimal, common level of regulation.

Many other countries – the United States among them – export successfully to the EU without being part of the Single Market without paying a cent to the EU. In 2015, you exported $273 billion in goods to the EU and imported $426 billion. Your service exports were worth $219 billion and European imports $169 billion. Why, then, is it essential for the UK to be a member of the Single Market? It is absurd to demand that the UK regulate its whole economy to meet EU product standards on exports; we can do the same as the US and the rest of the world.

Customs Union

While we remain in the Customs Union, we cannot pursue our own trade deals. Its advocates like to portray it as a co-operative trading association of Member States – akin to an economic version of NATO – but it is not. In setting the Common External Tariff, the Customs Union denies its Members the right to set their own trade policies and forces them behind a protectionist wall separating the EU from the rest of the world. New free-trade deals may be struck only by the slow, bureaucratic Union and not by Member States individually. EU trade negotiations need the agreement of 28 nations, so limp along at the pace of the lamest camel in the caravan. Consequently, the EU has so far not concluded a free-trade deal with the US, Japan, China or India. Most existing EU free-trade deals are, in fact, roll overs from the colonial days of individual EU countries.

We must embrace quickly the trade opportunities offered around the world. Last year, our trade surplus with the rest of the world was $46.4 billion. With the USA $53 billion, with Canada $1.8 billion and Australia $5 billion.

India's GDP has grown between 7 and 10% each year for the last decade as a result of economic liberalisation, and Brazil's average growth since 2010 has been over 3% per year.

To take full advantage of the opportunities which these economies present, we must, therefore, leave the Customs Union. To the UK, the economic case is clear. Expert analysis from Professor Patrick Minford concludes that leaving the Single Market and Customs Union will provide a saving of $400 per household per annum on food bills, or some $10.8 billion overall. It will also bring down consumer prices more generally, by around 8% overall; and stimulate competition across the economy, raising productivity and GDP by around 4%.

Minford's modelling is based upon unilateral free trade, and assumes no subsequent reciprocal arrangements. The same results can be achieved by Free Trade Agreements with our main trading partners, notably the US.

Although the Commissioners of the EU might protest, the economic case for its Member States to continue to trade freely with the UK is strong. The UK runs a monumental deficit of almost $100 billion a year with the EU. That figure went up by $13 billion last year alone.

Deloitte have explored the potential effect of a "tariff war" on the German car industry, which exports 1 in 7 of its cars to the UK. They assume a 10% tariff on vehicles and a 4.5% tariff on parts. They believe that EU carmakers will lose $10 billion a year worth of revenues, with $8 billion from German carmakers alone. In the first 12 months after the UK leaves, German car exports to the UK would collapse by 255,000 units, representing a 32% decline, with 18,000 jobs in the German car industry put at direct risk.

We currently have zero tariffs, and conformity of regulations and standards is already in place. Spiteful protectionism from the Commission would accomplish nothing but impoverishing all sides and is illegal under WTO rules. There ought to be no reason that independent countries cannot trade freely, and no reason whatsoever that free trade cannot be maintained with a fully-fledged free trade pact. Reciprocal free trade is in all our best interests.

If the EU refuses to have a free trade agreement with the UK, it will have far less effect on the UK than on the EU: EU tariffs averaging some 3% can be absorbed by our manufacturers or they can easily divert some output to other markets but if we impose the same tariffs on EU manufacturers they will lose profits in the UK on top of the much tougher competition they will face from non-EU

suppliers with whom we have trade agreements. US and New Zealand quality wine producers will be able to compete on level terms once we have torn down the tariff barriers of Fortress Europe.

Furthermore we are unlikely to pay the EU any 'divorce money' if there is no trade agreement. 'No deal' holds no horrors for us; remember too that the EU must under WTO rules on non-discrimination provide the same seamless Customs procedures and mutual recognition agreements that it provides to other countries.

The case for free trade, however is not based solely upon utility but upon justice; the moral case is as strong as the economic one. The United Kingdom will be bold in stating it.

The Customs Union has caused inequities in the European attitude to trade with the developing world. As the trade adviser for the charity Oxfam put it in 2006, "Not only does the Common Agricultural Policy hit European shoppers in their pockets but strikes a blow against the heart of development in places like Africa."

As an example, after oil, coffee is the second most traded commodity in the world. The entire continent of Africa exports coffee to the European Union with a value of $2.4 billion, while Germany, without growing a single bean, earns $3.8 billion on exports of coffee.

How can this be? The EU customs union has no tariff on raw beans, but any added-value product is penalised. A 7.5 per cent tariff is imposed on roasted coffee, ensuring that added value remains inside the EU and is denied to poorer African countries. This results in higher prices in our shops and further denies African nations the chance to add value themselves, creating the investment and jobs they need to grow.

Some will say that many developing world exports come in duty free or at low duties because of Generalised Scheme of Preferences or European Banking Authority programmes. But this is even less moral; it locks producers into arrangements and sets up a situation where they want the Most Favoured Nation tariff rate to remain high so their preferences remain in place. This is Alice Through the Looking Glass – a transfer of wealth from poor European consumers to vested-interest elites in developing countries propping up the worst kind of crony capitalism. So much for a benign project of economic co-operation.

Immigration

It is not merely trade where the Customs Union has done its damage; it also adversely affects migration. Ghanaians consume tomatoes with virtually every meal, but the tomato industry in Ghana has been all but destroyed as a result of the dumping of subsidised Italian tinned tomatoes. Because of European tariffs, Ghanaian farmers are instead forced to migrate, often illegally, to work on the harvest in Italy rather than farm their own land. The protectionism of the Customs Union, therefore, is placing direct pressure on the borders of Europe and has played a clear role in precipitating the migrant crisis.

Beyond that, however, is the simple question of principle. A sovereign nation should fully control its own borders.

We recognise the skills and experience brought by workers and students. Whether they are eye surgeons from Bangalore or skilled abattoir workers from Eastern Europe, it is manifestly in our national interest to attract the best talent from across the world.

But we must be realistic. The UK's population grew by a record 513,300 last year, to 65.1 million, with net migration at 335,600. The homelessness charity Shelter suggests that, in a country roughly the size of Michigan, we would need to build a new home every 2 minutes – night and day, every year – so long as current migration levels are maintained.

Once we acknowledge that some restrictions are sensible, why should we be prejudiced in favour of Europeans over, say, those from the Commonwealth or the Anglosphere?

Instead, a new, bespoke immigration policy must be designed to meet the needs of British commerce according to fluctuating demands for skilled labour. The principles must be very simple: The United Kingdom will control its own borders, the discrimination against non-Europeans will end, and we will make — in Parliament — democratic, accountable decisions on immigration.

The European Court of Justice

The European Union's chief representatives have yet to adopt such a pragmatic mentality. Over the summer, the British Government released a number of initial position papers relating to key areas of negotiating policy, to which the Brussels response has been ludicrously obstinate. President Juncker shrugged that the EU had received "no definitive response" from the UK on the question of the Irish border, despite the Government publishing a 30-page document on that very subject. The arguments were not countered, not constructively appraised, but simply dismissed as not fitting the arch-federalist agenda.

In reply, the EU has made a series of outlandish demands for an arbitrary "divorce bill" of $120 billion— rejected by the UK with a forensic legal rebuttal.

We will, of course, pay what we legally owe. Edward III's refusal to pay the Bardi and Peruzzi families in 14th century Florence was the last time the UK failed to honour its international obligations. We are also likely to continue contributing to a number of European educational and research schemes such as Horizon 2020 and Erasmus.

But recent reports by the House of Lords and respected lawyer Martin Howe QC establish that there is no credible legal argument obliging the UK to continue contributing to the EU's ongoing programmes after Brexit. Our attitude echoes that of George Washington, who wrote in a letter to Alexander Hamilton in 1796:

"We will not be dictated to by the Politics of any Nation under Heaven, farther than Treaties require of us."

The European Commission has also demanded that the European Court of Justice – the highest court in the EU – continues to rule on the rights of EU citizens in the UK after Brexit. If immigration was a manifestation of Britain's non-independence, then the continuing remit of the ECJ would surely be confirmation of it.

There is no exact legal precedent for such a bizarre suggestion, which would create a privileged class of over 3 million EU residents in the UK, whose rights would be enforced by a court beyond the influence of our government and Parliament.

Its closest parallel comes from the nineteenth century, when the British Supreme Court for China exercised extra-territorial jurisdiction over British citizens in concessions such as Shanghai, who were not subject to the jurisdiction of the Chinese courts.

The British government has, quite rightly, ruled this out. Independent sovereign nations cannot be bound by rulings of the courts of other nations. Once again, George Washington put our approach perfectly in that same letter to Hamilton:

"If we are to be told by a foreign Power…what we shall do, and what we shall not do, we have Independence yet to seek, and have contended hitherto for very little."

That is not to say that British courts should give no attention to future decisions of the ECJ. It is standard practice across the world for the courts of countries in an international treaty to pay attention to the judgments of their partners, and to try, if possible, to apply a consistent interpretation.

As the late Justice Scalia of your Supreme Court – himself no friend of foreign judgments influencing US courts – said:

"We can, and should, look to decisions of other signatories when we interpret treaty provisions... Even if we disagree, we surely owe the conclusions reached by appellate courts of other signatories the courtesy of respectful consideration."

It would be inconceivable for the US to accept any court overruling its own Supreme Court, but it has always been accepted that account be taken of preceding legal decisions.

Take, for example, the case of Amalfitano v. Rosenberg in New York in 2009. The Court of Appeals ruled that "attempted deceit" was sufficient to sustain a cause of action under judiciary law Section 487, on the basis that it derived not from common-law fraud, but from the first Statute of Westminster – a criminal statute adopted by the Parliament of Edward I in England in 1275.

We will adopt just the same attitude towards the ECJ's preceding decisions. But, as a simple matter of principle, we cannot accept continuing ECJ jurisdiction once we have regained independence.

Opportunities for the United States

Increasingly, regulation is being made at world level. As a member of the EU, we have been represented as 1/28th of a vote on the world bodies – the WTO, the World Organisation for Animal Health (OIE), the Codex Alimentarius Commission and the International Plant Protection Convention.

We have been prevented from working with like-minded countries to tackle pressing policy concerns and prevented from reaching trade agreements with countries which would buy our produce. We can now retake our full seat – regaining a right to vote, a right to initiate new standards and propose amendments to existing ones – determined to co-operate with old friends in the Anglosphere and forge new alliances.

For the US, this means regaining a partner at those regulatory tables committed to global free trade, determined to embrace new technology, whose values of freedom and democracy you share.

Britain has no greater ally than the United States. It was, therefore, disappointing – but perhaps not surprising— to hear President Obama opine last year that "the UK is going to be in the back of the queue" for post-Brexit trade talks, so it is welcome that the new Administration is as pro-British as any we have seen since the Second World War. Your new ambassador to the UK, Woody Johnson,

got off to a great start when he said last month "As far as the President is concerned, the United Kingdom, our most enduring ally, is always ahead of the line."

The "Special Relationship" has been a cornerstone of our foreign policy for 70 years, whether that is procurement and development — the UK is the only Level One partner in the largest aircraft procurement programme in US history, the F35 Lightning II — or our comprehensive intelligence sharing schemes.

But our ties to the United States run far deeper than that. We are united by our history, our culture and, perhaps most of all, by our language. With such strong and long-standing bonds, we should all be very optimistic about a new US-UK trade deal being, as President Trump put it, "very big and exciting!"

Indeed, as your new ambassador put it:

"Britain's decision to leave the European Union takes your country into new territory — but you are not heading there on your own. The United States is committed to standing with the UK through Brexit…whatever the outcome of the negotiations between the UK and the EU, Britain should know you will have a strong and reliable trade and investment partner in America."

Conclusions

In the months and years ahead, Britain must be guided above all by the decision which its people made in June 2016. The constitutional position we face is unprecedented. We have held a number of referendums over the last 50 years, but this is the first in which the people have contradicted the view of the political, judicial, financial, media and academic Establishment. Failure now to deliver what 17.4 million people voted for would do catastrophic damage to the integrity of the whole Establishment.

We will leave the political and legal arrangements of the European Union. In a whole range of fields – security, academia, scientific research, cultural exchanges – we look forward to maintaining the closest possible co-operation with the EU. What we are offering is a vision of amicable, reciprocal free trade between sovereign nations, close neighbours and good friends.

Whether the Commissars of the EU choose to engage constructively with that process — or choose to remain stubborn and intransigent — is their own affair. In any event, the United Kingdom intends to be bold and ambitious, retaking our place as a dynamic, globally-oriented nation.

For the United States, this is unequivocally good news; you are regaining an independent ally in trade and on the global bodies which determine world regulation. The Special Relationship will go from strength to strength, in George Washington's words, to "animate and encourage each other, and show the whole world, that a Freeman contending for Liberty on his own ground is superior to any slavish mercenary on earth."

MEMORANDUM

As discussed in greatly detail below, DOE and EPA have the authority to issue a rule that expressly preempts Energy Star class actions pursuant to their authority to protect the integrity of the program. A preemption rule from the EPA or DOE would help prospectively, meaning that any future Energy Star class actions would be preempted in accordance with the language of the regulation. The specific regulatory language and agency history would determine whether that rule could also be used to argue that existing claims are also preempted. In particular, a rule that references prior agency statements consistent with Energy Star preemption rule and states that the rule is reaffirming prior agency positions—such as the February 13, 2014 white paper—would be particularly useful in arguing that the rulemaking supports a preemption argument.

A. The DOE and EPA Possess Authority to Regulate the Energy Star Program

The Energy Star program was created by the EPA in 1992 to promote energy efficient computer equipment. In 1996, the DOE became co-administrator of the program. Explicit statutory authority for the Energy Star program was added to the Energy Policy and Conservation Act in 2005. 42 U.S.C.A. § 6294a grants the EPA and DOE agencies broad authority to govern the Energy Star program, essentially instructing those agencies to work out a division of labor. Subsection (b) of the statute provides:

Responsibilities under the program shall be divided between the Department of Energy and the Environmental Protection Agency in accordance with the terms of applicable agreements between those agencies. These "responsibilities" include "preserv[ing] the integrity of the Energy Star label." 42 U.S.C.A. § 6294a(c)(3).

Agency pronouncements with respect to Energy Star have been informal, including the current DOE/EPA Memorandum of Understanding ("MOU") that sets out the division of labor between the two agencies. However, there is nothing preventing the DOE and EPA from issuing formal rules regarding the Energy Star program. The current version of the MOU places responsibility for enforcement with EPA, but the EPA and DOE can modify their MOU however they wish.

The agencies have previously issued formal rules that give informal Energy Star pronouncements legal affect by incorporating them into regulations. For example, 10 C.F.R. § 430.3(n) incorporates by reference certain Energy Star testing guidance and program requirements. The uniform test for measuring the energy consumption of illuminated "exit" signs is simply borrowed by reference from the Energy Star program. 10 C.F.R. § 431.204. Formal regulations also exist to govern the labeling of Energy Star-qualified appliances:

> Only manufacturers that have signed a Memorandum of Understanding with the Department of Energy or the Environmental Protection Agency may add the ENERGY STAR logo to labels on qualifying covered products; such manufacturers may add the ENERGY STAR logo to labels only on those covered products that are contemplated by the Memorandum of Understanding.

16 C.F.R. § 305.11.

Accordingly, the DOE and EPA possess authority to promulgate Energy Star regulations and already have.

B. Federal Agencies Can Issue Rules that Preempt Certain Claims

There is ample precedent for federal agencies to include broad preemption provisions in their regulations. In 2005, the National Highway Traffic Safety Administration—part of the Department of Transportation—issued a notice of proposed rulemaking regarding rear object detection systems, and included a discussion of the preemptive intent of the regulation. Note the underlined language below, which is clearly designed to mirror the requirements of field and obstacle preemption:

> If adopted, our proposed amendments would preempt all state statutes, regulations and common law requirements that differ with it. More specifically, the amended FMVSS No. 111 would preempt State requirements for a rear object detection system on new motor vehicles that is not the same as the one that would be required under the standard. Thus, for example, it would preempt aspects of at least three State laws currently in force (i.e., provisions in New Jersey, New York, and Washington).
>
> Our proposal reflects careful balancing of a variety of considerations and objectives in this field. As a primary matter, we believe that the proposal should reflect the fact that drivers have the responsibility to ensure that the pathway is clear before backing the vehicle. To this end, the NPRM is proposing several technological options that would ensure that drivers can visually confirm that the pathway is clear, including cross-view mirrors, a rear video camera, or even the driver's vision (if the configuration of the vehicle is such that the driver can see all relevant test points). We have concerns that non-visual systems, such as infrared and sonar systems, may not be sufficiently reliable or provide the same level of certainty as visual systems. We are also concerned that other systems, such as audible back-up alarms, could shift the burden to the person behind the backing vehicle to get out of the way; some pedestrians (e.g., children, the elderly) may be ill-equipped to take the necessary evasive action in those situations. Thus, we believe that requiring a visual rear object detection system, as proposed, would adequately address the identified backing problem with straight trucks.
>
> We also intend to specify a uniform set of requirements for rear object detection systems installed on straight trucks consistent with the Federal system established by Congress. Congress provided NHTSA with the responsibility to establish performance standards to ensure that motor vehicles—including straight trucks—are manufactured in such a way as to meet the need for motor vehicle safety. Congress gave FMCSA the responsibility to ensure that straight trucks are operationally safe in accordance with a uniform Federal, rather than a myriad of State, operational standards. As noted above, FMCSA has concluded that States

> should adopt requirements consistent with the FMVSS or should limit State requirements to vehicles that will operate solely in intrastate commerce. Although we do not propose to prohibit the voluntary installation of supplemental systems by manufacturers, we believe our proposal addresses the safety need and that supplemental State or local requirements would subvert the Federal safety program Congress has established between NHTSA and FMCSA.

Federal Motor Vehicle Safety Standards; Rearview Mirrors, 70 Fed. Reg. 53753 (proposed Sept. 12, 2005).[1]

The DOE or EPA could issue a rule with similar language affirming the preemptive purpose and effect of their disqualification decisions.

C. Federal Agencies Cannot Promulgate Retroactive Regulations Without Express Congressional Authorization, But May Pass Rules Restating Pre-existing Rules

Agencies do ***not*** have the authority to retroactively preempt claims through rulemaking. "It is well settled that an agency may not promulgate a retroactive rule absent express congressional authorization." *Ne. Hosp. Corp. v. Sebelius*, 657 F.3d 1, 13 (D.C. Cir. 2011) (citing *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988)). "Rulemaking, moreover, includes not only the agency's process of formulating a rule, but also the agency's process of modifying a rule." *Id.* In *Arkema Inc. v. E.P.A.*, the D.C. Circuit "lamented" that "the retroactivity rules are easy to state, less easy to apply." 618 F.3d 1, 6–10 (D.C. Cir. 2010). The *Arkema* court summarized the retroactivity rules as follow:

> A rule operates retroactively if it takes away or impairs vested rights. The critical question is whether the interpretation established by the new rule 'changes the legal landscape.' If a new rule is 'substantively inconsistent' with a prior agency practice and attaches new legal consequences to events completed before its enactment, it operates retroactively. Even where a rule merely narrows 'a range of possible interpretations' to a single 'precise interpretation,' it may change the legal landscape in a way that is impermissibly retroactive.

Id. (citations omitted).

Agencies ***do*** have the authority to restate and reinterpret existing agency policy, and in such instances, courts are less likely to find such rules to be retroactive. For example, in *Forsyth Mem'l Hosp. Inc. v. Sebelius*, 667 F. Supp. 2d 143, 149 (D.D.C. 2009), *aff'd*, 639 F.3d 534 (D.C. Cir. 2011), the court considered an agency memorandum that offered a new interpretation of the phrase "bona fide sale" as that term was used in a regulation. The court acknowledged that the memorandum clarified the standard, but held that the new interpretation did "not stray far from the regulation itself," and was therefore valid. *Id.* Similarly, in *Louisiana v. Salazar*, 170 F. Supp. 3d 75, 91 n.17 (D.D.C. 2016), the court held that the Department of Interior's revised approach

[1] This proposed rule was withdrawn in light of the passage of a federal statute regarding the same subject matter. After the 2008 election, the Obama DOT issued a revised rule which acknowledged the "possibility" of preemption but did not affirmatively claim preemptive affect.)

to calculating oil and gas revenues "is not impermissibly retroactive as suggested by the plaintiffs [because the] defendants are merely *correcting their interpretation* of an existing law."

As would be expected, litigants often fight over whether an announced rule is "retroactive" or simply a restating of a previous rule. For example, in *Ne. Hosp. Corp.*, the Department of Health and Human Services argued that a new rule which modified Medicare reimbursement procedures merely "codified a longstanding policy." 657 F.3d at 15. However, hospitals presented voluminous evidence indicating that the Department's prior practice was indeed different, and therefore HSS's new rule was indeed a change in policy and can therefore only be applied prospectively. *Id.*

Message

From: Jennifer Gibson [JGibson@NACD.com]
Sent: 9/26/2017 1:44:10 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: EPA Cut the Red Tape Event

Hi Mandy.

Hope all is well with you! NACD has received a few invitations for various agency Cut the Red Tape events for Monday, October 2. Do you know if EPA is planning to hold such an event?

Best regards,

Jennifer

Jennifer C. Gibson
Vice President, Regulatory Affairs

National Association of Chemical Distributors (NACD)

nacd
National Association of Chemical Distributors

1560 Wilson Blvd., Suite 1100
Arlington, VA 22209
(703) 527-6223 x3047 - Main Line
(703) 527-7747 - Fax
(571) 482-3047 - Direct
jgibson@nacd.com
LinkedIn

Message

From: Rachel Jones [RJones@nam.org]
Sent: 9/27/2017 9:32:49 PM
To: Lovell, Will (William) [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=3b150bb6ade640f68d744fadcb83a73e-Lovell, Wil]
CC: Kime, Robin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=7ef7b76087a6475b80fc984ac2dd4497-RKime]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting Notice

Will—I just spoke with Mandy and she said that she can step in tomorrow morning. So crisis averted!

Alex—Please let me know if you need additional details to those below. I'll be staffing an event this evening but will be available by cell.

Thanks!

Rachel Jones
National Association of Manufacturers
Director, Energy and Resources Policy
E-mail: rjones@nam.org
Direct: (202) 637-3175
Mobile: (804) 380-6542

NATIONAL ASSOCIATION OF Manufacturers

From: Lovell, Will (William) [mailto:lovell.william@epa.gov]
Sent: Wednesday, September 27, 2017 5:10 PM
To: Rachel Jones <RJones@nam.org>
Cc: Kime, Robin <Kime.Robin@epa.gov>
Subject: RE: Meeting Notice

Rachel,

I am extremely sorry, but Samantha will not be able to make it tomorrow. Very last minute travel with the Administrator just came up today and we finalized her travel plans recently. Additionally, Brittany is also travelling for work tomorrow so she cannot go in her stead.

If you will still have her, I hope we can arrange for another meeting in the future. I have cc'd the Chief of Staff for the Office of Policy, Robin Kime, to help coordinate such a meeting. Again, I cannot apologize enough for the inconvenience caused by this turn of events.

Sincerely,

Will

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Wednesday, September 27, 2017 5:02 PM
To: Lovell, Will (William) <lovell.william@epa.gov>
Subject: RE: Meeting Notice

All good for in the morning?

Rachel Jones
(202) 637-3175

From: Lovell, Will (William) [mailto:lovell.william@epa.gov]
Sent: Friday, September 22, 2017 10:37 AM
To: Rachel Jones <RJones@nam.org>
Subject: RE: Meeting Notice

Thank you, Rachel!

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Friday, September 22, 2017 10:34 AM
To: Lovell, Will (William) <lovell.william@epa.gov>
Subject: Meeting Notice

I wanted to send you a copy. Please let me know if you guys need anything. Thanks!

Rachel Jones
(202) 637-3175

From: Ross Eisenberg, NAM [mailto:Ross.E.Eisenberg@nam.org]
Sent: Wednesday, September 20, 2017 11:36 AM
To: Rachel Jones <RJones@nam.org>
Subject: Meeting Notice - Energy Forum, September 28 at the NAM

Energy Forum

A Joint Project of ACC, AFPM, API, INGAA, NAM, and the U.S. Chamber

Dear Energy and Natural Resources Committee Members:

Our next Energy Forum will take place on September 28, 2017 and will feature Samantha Dravis, Associate Administrator for the Office of Policy at the U.S. Environmental Protection Agency.

Attendance is in-person only, and *seating will be limited*. If you would like to attend, please RSVP here.

Thursday, September 28, 2017
10:00 am – 11:00 am
National Association of Manufacturers
733 10th Street, Suite 700
Washington, DC 20001

We will continue to hold these events every two weeks, rotating speakers among the federal agencies and relevant congressional committees of jurisdiction. We hope this will be a valuable way to obtain up-to-date

information from the key players making policy in Washington. As a reminder: the meetings will be in-person attendance only, closed-press and off-the-record.

We look forward to seeing you on September 28th.

Thanks,
Ross

Ross Eisenberg
Vice President, Energy and Resources Policy
National Association of Manufacturers
Direct: 202.637.3173
Mobile: 703.517.1655
Email: reisenberg@nam.org

To no longer receive invites to NAM's Energy Forums, click here.

Message

From: David Jory [djory@capitolhillcg.com]
Sent: 9/27/2017 1:39:35 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Ryan Cunius [rcunius@capitolhillcg.com]; Patterson, Ashley [apatterson@ameresco.com]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Ameresco Meeting Request

Thank you very much. Looking forward to seeing Mandy and you next week. Best, David Jory

David C. Jory
Capitol Hill Consulting
202 236 5731

On Sep 27, 2017, at 8:21 AM, Dominguez, Alexander <dominguez.alexander@epa.gov> wrote:

> Apologies – resending as we apparently had an issue with our server this morning.
>
> **From:** Dominguez, Alexander
> **Sent:** Wednesday, September 27, 2017 8:02 AM
> **To:** 'Ryan Cunius' <rcunius@capitolhillcg.com>
> **Cc:** David Jory <djory@capitolhillcg.com>; Patterson, Ashley <apatterson@ameresco.com>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** RE: Ameresco Meeting Request
>
> Thank you for the quick response and the information.
>
> We are confirmed for Thursday, October 5th at 3:00PM.
>
> Location: 1200 Pennsylvania Avenue, NW.
>
> Directions: Please use the William Jefferson Clinton **North Entrance** located on your right as you exit the Federal Triangle Metro Station.
> https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg
>
> EPA Contact: For an escort from Security to the meeting call me at 202-578-5985 or 202-564-3164
>
> Looking forward to it and please let me know if you need anything in the meantime.
>
> Best,
> Alex
>
> **Alex Dominguez**
> *Policy Analyst to the Senior Advisors to the Administrator for Air and Water*
> U.S. Environmental Protection Agency

From: Ryan Cunius [mailto:rcunius@capitolhillcg.com]
Sent: Tuesday, September 26, 2017 6:01 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: David Jory <djory@capitolhillcg.com>; Patterson, Ashley <apatterson@ameresco.com>
Subject: RE: Ameresco Meeting Request

Alex,

3:00 pm works for us.

Attendees will be:

- <!--[if !supportLists]--><!--[endif]-->Ashley Patterson, Vice President, Government Relations & Public Policy, Ameresco
- <!--[if !supportLists]--><!--[endif]-->David A. Cox, Director of Operations & General Counsel, Renewable Natural Gas Coalition
- <!--[if !supportLists]--><!--[endif]-->David Jory, President, Capitol Hill Consulting Group.

Topics to be discussed:

- <!--[if !supportLists]--><!--[endif]-->On July 5, EPA issued its 2018 draft rule Renewable Volume Obligation (RVO) for the Renewable Fuel Standard (RFS). The draft rule includes a 2018 RVO of 238 million gallons for Cellulosic Biofuel (D3 & D7 RINS).

- <!--[if !supportLists]--><!--[endif]-->The Coalition for Renewable Natural Gas (RNG Coalition) is a non-profit association of companies and organizations dedicated to the advancement of renewable natural gas. Ameresco is a member of the RNG Coalition and is a leading producer of cellulosic biofuel under the RFS generating D3 RINs.

- <!--[if !supportLists]--><!--[endif]-->Renewable Natural Gas has supplied 98% of the RFS's Cellulosic Biofuel market since it received the D3 RIN designation in July 2014.

Materials are attached to the email.

Let me know if you need anything else.

Best,
Ryan

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 26, 2017 5:24 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Ryan Cunius <rcunius@capitolhillcg.com>
Cc: David Jory <djory@capitolhillcg.com>; Patterson, Ashley <apatterson@ameresco.com>
Subject: RE: Ameresco Meeting Request

Hey Ryan,

Happy to set something up. Could you do 3:00 or 3:30 on Thursday, October 5th?

Additionally, I need a few pieces of information from you:

- List of attendees
- Description of topics to be discussed.
- Any relevant materials.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Gunasekara, Mandy
Sent: Tuesday, September 26, 2017 7:55 AM
To: Ryan Cunius <rcunius@capitolhillcg.com>
Cc: David Jory <djory@capitolhillcg.com>; Patterson, Ashley <apatterson@ameresco.com>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: Ameresco Meeting Request

Hi Ryan,
I'd be happy to meet. I've CC'd Alex who can help figure out the logistics on my end.
Best,
Mandy

Sent from my iPhone

On Sep 25, 2017, at 5:22 PM, Ryan Cunius <rcunius@capitolhillcg.com> wrote:

> Mandy,
>
> My boss, David Jory, President of Capitol Hill Consulting Group, would like to request a meeting with you on behalf of Ameresco. They would like to discuss the 2018 RVO with you and will have the chief counsel of the Renewable Natural Gas Coalition in town to join the discussion as well. We are looking to meet on October 4th or 5th. Hope to hear back from you soon!
>
> Best,
>
> Ryan Cunius
> Legislative Assistant
> <image002.jpg>
> Capitol Hill Consulting Group
> Government Relations Professionals
> 499 S. Capitol Street, SW

Suite 608
Washington, DC 20003

Cell: (813) 713-5062
Office: (202) 488-0101
Web: capitolhillcg.com

<image004.jpg> <image006.jpg>

Message

From: Ashley Featherstone [Ashley.Featherstone@buncombecounty.org]
Sent: 9/27/2017 9:24:44 PM
To: Banister, Beverly [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=1d7573525c894f5dbfc19abd6a7fda91-Banister, Beverly]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Kemker, Carol [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=765ad99166db4233bd15febf6e9917b3-Kemker, Carol]; michael.abraczinskas@ncdenr.gov [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=75effabe4e91420f949b80e5001d9b18-michael.abraczinskas@ncdenr.gov]; Ceron, Heather [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=b03966abf9ea4f0490c8fe49ed5519b4-Ceron, Heather]; david.brigman@buncombecounty.org [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=08a1ee96e74c4617bd62de74ca06c39a-david.brigman@buncombecounty.org]; Johnson, Terry [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=37884c5ac1ab48e4b6a8e4248d588f88-Johnson, Terry]
Subject: WNC response to Duke Asheville Order
Attachments: WNC Response to Order.pdf

Beverly,

Please find attached WNCRAQA's response to the June 30, 2017 Order regarding the Title V permit that was issued to Duke Energy Progress in 2016. We are sending a hard copy to you in the mail.

Thanks,
Ashley

Ashley Featherstone
Permitting Program Manager
WNC Regional Air Quality Agency
P.O. Box 2749, Asheville, NC 28802
52 Coxe Avenue, Asheville NC 28801
Phone: 828.250.6778
Fax: 828.250.6222
http://www.wncairquality.org
ashley.featherstone@buncombecounty.org

Follow us on Facebook, Twitter, and Youtube!

All correspondence to and from this address may be subject to the N.C. Public Records Law and may be disclosed to third parties.

Western North Carolina **Regional Air Quality Agency**

David A. Brigman, Director

Serving Buncombe County and the City of Asheville

September 28, 2017

Beverly Banister
U.S. Environmental Protection Agency, Region 4
Sam Nunn Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-8960

Subject: Response to Final Order issued by EPA for Duke Energy Progress, Inc. Asheville Steam Plant Title V Permit

Dear Ms. Banister:

The Western North Carolina Regional Air Quality Agency (WNCRAQA) received an order from the United States Environmental Protection Agency (EPA) granting a petition for objection to the Duke Energy Progress, Inc. Asheville Steam Plant Title V permit (No. 11-628-16) on June 30, 2017. The EPA order was in response to a petition from the Sierra Club dated June 17, 2016.

In responding to the petition, EPA noted that the Petitioner had demonstrated that the Title V permit and permit record are "unclear" and the response to comments by WNCRAQA is "insufficient" (Order, p.14). In the EPA's direction to WNCRAQA in the order, it requires an expanded response to comments, not a change to the permit itself. Further, in a letter dated August 8, 2017 to the North Carolina Department of Environmental Quality (NCDEQ) regarding a nearly identical order for the Duke Energy Roxboro permit, EPA Administrator Pruitt, indicated EPA "was unable to determine" how The North Carolina Division of Air Quality (DAQ) within the (NCDEQ) interprets and applies rules that EPA has approved into North Carolina's State Implementation Plan (SIP). WNCRAQA adopts NC DAQ rules by reference. Our agency has consulted with DAQ and concurs with them on the following points.

In reviewing the language in Section 505(b)(2) of the Clean Air Act (CAA), a standard of review is established regarding Title V petitions. It reads: "*The Administrator shall issue an objection within such period if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of this chapter, including the requirements of the applicable implementation plan.*"

In reviewing this matter, it appears the Administrator granted the petition not because the petitioner had demonstrated the permit failed to comply with the requirements of the CAA, but because the EPA found that there was a lack of clarity in the review documents. "*...the EPA finds that the permit record as a whole is inadequate for the EPA to sufficiently evaluate the Petitioner's claim ...*" (Order p.16). Therefore, in the absence of any findings by EPA of deficiency in the permit, we conclude that EPA's granting of Sierra Club's petition does not require action under Section 505 of the CAA.

PO Box 2749 Asheville, NC 28802
Telephone: (828) 250-6777 Fax: (828) 250-6222 Web Address: www.wncairquality.org
E-Mail: wncair@buncombecounty.org

EPA-HQ-2018-002296

Despite our concerns enumerated above, we are responding to the specific text on page 17 of the order ("Direction to the WNCRAQA"). The attached document provides an expanded response to comments in the Statement of Basis (also referred to as the Permit Review document) that directly addresses the order. We believe our changes to the Statement of Basis close this matter.

We look forward to continuing to work together with EPA on the common goal of protecting and improving air quality for our citizens.

Sincerely,

David A. Brigman
Director

cc: Mandy Gunasekara, EPA
Michael Abraczinskas, NC DAQ

Attachment

ED_002110_00032508-00002

Attachment

Date: September 28, 2017

Addendum to the permit review for Title V permit No. 11-628-16, issued July 11, 2016

WNCRAQA offers the following expanded response to the Sierra Club's comments dated April 30, 2015.

WNCRAQA affirms, consistent with the NC DAQ's March 18, 2014 infrastructure SIP submittal for the 2010 1-hour SO2 NAAQS (relevant portions approved by EPA as of May 26, 2016), that WNCRAQA is operating under a state plan which provides for implementation, maintenance, and enforcement of the NAAQS. Amongst the regulatory tools available to carry out the NAAQS are the rules in Sections .0400 and .0500 of Subchapter 02D in Title 15A of the North Carolina Administrative Code (NCAC), adopted by reference in Chapter 4 .0400 and Chapter 4 .0500 of the WNCRAQA Code. Amongst other things, the provisions in Chapter 4 .0401 provide for the enforcement of the ambient standards predicated on monitored concentrations of pollutants in ambient air. Next, in Chapter 4 .0501, WNCRAQA is provided the authority to issue a permit with conditions that prevent a violation of the ambient air quality standards in Chapter 4 .0400. It is important to note that this regulatory framework provides the WNCRAQA with the proper tools to address monitored exceedances of ambient standards, while also providing the agency the discretion to act before a violation occurs.

An additional regulatory tool, important in this matter, is EPA's Data Requirements Rule (DRR) for the 2010 1-hour SO_2 NAAQS. This federal rule establishes the criteria for identifying emissions sources and associated areas for which state and local air agencies are required to characterize SO_2 levels in ambient air. This regulation gives state agencies, including the DAQ, the flexibility to characterize air quality using either modeling of actual emissions or using appropriately sited ambient air quality monitors. In the case of the Duke Energy Progress Asheville Steam Plant, DAQ identified this facility as being subject to further air quality characterization, as required by the DRR, and chose the option to monitor air quality. DAQ and WNCRAQA have worked closely with EPA staff to establish an appropriately sited air quality monitor on the timelines required by the DRR. The monitor provides the DAQ and the WNCRAQA the opportunity to assess SO_2 levels in ambient air on a continuous basis. The use of a monitor fulfills the requirements of the DRR and it is fully consistent with WNCRAQA's authority under the SIP provisions cited above.

WNCRAQA's practical use of these regulatory tools and broad discretion rely on highly case specific facts. In the case of Duke Energy Asheville, we have not reached the point where more stringent control is required. However, WNCRAQA acknowledges that as the analysis continues via SO_2 ambient monitoring at Duke Energy Progress Asheville, consistent with the DRR, the case specific facts may evolve with time. WNCRAQA is confident that working with DAQ, it

has the regulatory tools to take additional steps to protect air quality in the vicinity of this facility.

Finally, the order requests that WNCRAQA explain how we address and enforce the 2010 1 hour SO_2 NAAQS, "Including it's PSD regulations at WNCRAQA Code 4.0530, as referenced in the RTC." It was stated in our initial response to comments document, "Should this facility submit an application for an increase in SO_2 emissions that triggers the PSD regulation (WNCRAQA Code 4.0530), the facility must demonstrate the project will not cause or contribute to a violation of the 1-hour SO_2 standard. Approval for an increase, including enforceable emission limitations, would be handled through the construction permit process. No modeling analysis is required for the 1-hour SO_2 standard at this time" (WNCRAQA RTC, page 6). This comment was meant to explain when modeling for the 1-hour SO_2 standard would be required, and why it was not required in 2015 as part of the Title V permit renewal process. No changes were being made to the facility and the DRR had been proposed, but not finalized at the time that the response was written. As such, no modeling for the 2010 SO_2 standard was required by the agency as part of the permit renewal process.

Message

From: Scott Brenner [scott@rosemontstrategies.com]
Sent: 10/10/2017 2:26:35 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Some guidance please

Good Morning Mandy,

In talking with the folks from Caterpillar this morning, I discovered that they too are having trouble with EPA regulations concerning locomotive emissions and the emission credit program. Would greatly appreciate the opportunity to have Caterpillar and New York Air Brake come in to brief you on the issue. Please let me know if you are available or if there is someone else in the Department we should reach out to.

Thank you.

Scott

From: Scott Brenner
Sent: Thursday, September 14, 2017 3:27:12 PM
To: Gunasekara, Mandy
Subject: Some guidance please

Hey Mandy,

Lee Forsgren and I used to work together at the House T&I committee and he recommended that I talk to you about a challenge I'm facing at the EPA.

Let me summarize for you. I represent New York Air Brake, who, amongst other things, makes a software that allows locomotives to operate more efficiently. Their product, called LEADER, is sold as an aftermarket part to most of the major rail operators, particularly Norfolk Southern.

We have been working with many in the OTAQ office attempting to get clarification on an EPA statute that determines when a locomotive can accrue emission credits if it is equipped with an EPA-approved emission reducing technology. LEADER is one such product. EPA says that if the locomotive is equipped with the technology at the time of manufacture, the locomotive owner can earn emission credits but if it is applied one day after manufacture, it is not eligible. LEADER is an aftermarket technology so the EPA says it is not eligible.

We have looked at the statute and we would disagree with OTAQs interpretation. I would greatly appreciate it if we could sit down with you and go over the statute.

Thanks for your consideration.

Scott

Scott Brenner
316 Pennsylvania Avenue, SE #501 | Washington, DC 20003
202-750-7646 | cell: 202-222-8825
Scott@Rosemontstrategies.com

ROSEMONT
STRATEGIES

Message

From: Wilcox, Jahan [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=88FD588E97D3405D869BCAE98D391984-WILCOX, JAH]
Sent: 10/10/2017 2:23:56 PM
To: John.m.mccormack@gmail.com
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: John, email us if you have additional question

Happy to answer on background as an agency official.

Jahan Wilcox
EPA
Strategic Communications Advisor
Work Cell: 202.309.0934
Work Email: wilcox.jahan@epa.gov

Message

From: Sasha Forsen, Green Plains Inc. [Sasha.Forsen@gpreinc.com]
Sent: 10/4/2017 7:33:35 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Green Plains/Industry update with Todd Becker

Hi Alex,

Thanks for getting back to me. What do you have open in November?

Regards,

Sasha Forsen | Public Relations Manager

phone: 402.315.1670 | email: Sasha.Forsen@gpreinc.com

Green Plains Inc.

1811 Aksarben Drive | Omaha, NE 68106

www.gpreinc.com | Facebook | Twitter

CONFIDENTIALITY NOTICE: The information contained in this email, including any attachments, is confidential information and is intended only for use by those to whom it is addressed and may be privileged or otherwise protected. If you are not the intended recipient, any disclosure, copying, printing or use of this information is prohibited. If you received this information in error, please notify Green Plains immediately via fax 402.884.8776 or email at info@gpreinc.com.

ENTITY NOTICE: Green Plains Inc. owns its assets and operates its businesses through various subsidiaries and also seconds its employees to the general partner of its affiliated public company, Green Plains Partners LP. As such, neither the domain name, the signature block or any other entity reference in this email shall imply such employee is working for the entity so identified. Rather, the actions, authorizations or statements made in any such email shall relate to the applicable Green Plains entity that is subject of the contract or other legal document to which the topic relates.

From: "Dominguez, Alexander" <dominguez.alexander@epa.gov>
Date: Tuesday, October 3, 2017 at 4:01 PM
To: Sasha Forsen <sasha.forsen@gpreinc.com>

Cc: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Subject: RE: Green Plains/Industry update with Todd Becker

Sasha –Wednesday afternoon is booked and we are really looking at November at this point. Happy to set up a call for the week of the 6th if you would like.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Sasha Forsen, Green Plains Inc. [mailto:Sasha.Forsen@gpreinc.com]
Sent: Tuesday, October 3, 2017 3:20 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Ford, Hayley <ford.hayley@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: Green Plains/Industry update with Todd Becker

The only other time that would work for Michelle and me would be 4pm and after on Wednesday.

Regards,

Sasha Forsen | Public Relations Manager
phone: 402.315.1670 | email: Sasha.Forsen@gpreinc.com

Green Plains Inc.
1811 Aksarben Drive | Omaha, NE 68106

www.gpreinc.com | Facebook | Twitter

CONFIDENTIALITY NOTICE: The information contained in this email, including any attachments, is confidential information and is intended only for use by those to whom it is addressed and may be privileged or otherwise protected. If you are not the intended recipient, any disclosure, copying, printing or use of this information is prohibited. If you received this information in error, please notify Green Plains immediately via fax 402.884.8776 or email at info@gpreinc.com.

ENTITY NOTICE: Green Plains Inc. owns its assets and operates its businesses through various subsidiaries and also seconds its employees to the general partner of its affiliated public company, Green Plains Partners LP. As such, neither the domain name, the signature block or any other entity reference in this email shall imply such employee is working for the entity so identified. Rather, the actions, authorizations or statements made in any such email shall relate to the applicable Green Plains entity that is subject of the contract or other legal document to which the topic relates.

From: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Date: Tuesday, October 3, 2017 at 2:15 PM
To: Sasha Forsen <sasha.forsen@gpreinc.com>
Cc: "Ford, Hayley" <ford.hayley@epa.gov>, "Dominguez, Alexander" <dominguez.alexander@epa.gov>
Subject: Re: Green Plains/Industry update with Todd Becker

Hi Sasha,

I'm looping in the administrators new scheduler Hayley (CC'd) with regard to the CEO meeting request.

On my end, Thursday is already booked. Is there another day that would work for you and Michelle? I'm looping in Alex (also CC'd) to help with those logistics.

Best,
Mandy

Sent from my iPhone

On Oct 3, 2017, at 2:52 PM, Sasha Forsen, Green Plains Inc. <Sasha.Forsen@gpreinc.com> wrote:

> Hi Mandy and Maddy,
>
> Hope your week is going well so far!
>
> Michelle Mapes and I will be in town next Thursday. Mandy – would you have a few minutes to sit down with us? We are still hoping to get our boss a meeting with the Administrator Pruitt, but would appreciate the opportunity to connect with you as well.
>
> Regards,
>
> Sasha Forsen | Public Relations Manager
> phone: 402.315.1670 | email: Sasha.Forsen@gpreinc.com
>
> *Green Plains Inc.*
> *1811 Aksarben Drive | Omaha, NE 68106*
>
> www.gpreinc.com | Facebook | Twitter
>
> **CONFIDENTIALITY NOTICE:** The information contained in this email, including any attachments, is confidential information and is intended only for use by those to whom it is addressed and may be privileged or otherwise protected. If you are not the intended recipient, any disclosure, copying, printing or use of this information is prohibited. If you received this information in error, please notify Green Plains immediately via fax 402.884.8776 or email at info@gpreinc.com.
>
> **ENTITY NOTICE**: Green Plains Inc. owns its assets and operates its businesses through various subsidiaries and also seconds its employees to the general partner of its affiliated public company, Green Plains Partners LP. As such, neither the domain name, the signature block or any other entity reference in this email shall imply such employee is working for the entity so identified. Rather, the actions, authorizations or statements made in any such email shall relate to the applicable Green Plains entity that is subject of the contract or other legal document to which the topic relates.

From: Sasha Forsen <sasha.forsen@gpreinc.com>
Date: Friday, September 29, 2017 at 12:41 PM
To: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>, "morris.madeline@epa.gov" <morris.madeline@epa.gov>
Subject: Re: Green Plains/Industry update with Todd Becker

Happy Friday!

Wanted to follow up on my note below.

Thank you!

Sasha Forsen | Public Relations Manager
phone: 402.315.1670 | email: Sasha.Forsen@gpreinc.com

Green Plains Inc.
1811 Aksarben Drive | Omaha, NE 68106

www.gpreinc.com | Facebook | Twitter

CONFIDENTIALITY NOTICE: The information contained in this email, including any attachments, is confidential information and is intended only for use by those to whom it is addressed and may be privileged or otherwise protected. If you are not the intended recipient, any disclosure, copying, printing or use of this information is prohibited. If you received this information in error, please notify Green Plains immediately via fax 402.884.8776 or email at info@gpreinc.com.

ENTITY NOTICE: Green Plains Inc. owns its assets and operates its businesses through various subsidiaries and also seconds its employees to the general partner of its affiliated public company, Green Plains Partners LP. As such, neither the domain name, the signature block or any other entity reference in this email shall imply such employee is working for the entity so identified. Rather, the actions, authorizations or statements made in any such email shall relate to the applicable Green Plains entity that is subject of the contract or other legal document to which the topic relates.

From: Sasha Forsen <sasha.forsen@gpreinc.com>
Date: Thursday, September 28, 2017 at 8:36 AM
To: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>, "morris.madeline@epa.gov" <morris.madeline@epa.gov>
Subject: Green Plains/Industry update with Todd Becker

Mandy and Maddy,

My boss, Todd Becker – CEO of Green Plains Inc., would like to arrange a time to meet with Administrator Pruitt as a follow up to their conversation a few months back in regards to ethanol industry related issues. Todd is an expert in assessing the domestic and global role of our industry and we believe that his knowledge is an asset to providing a broad perspective of biofuels.

Todd will make his schedule flexible for Administrator Pruitt. Please let us know when we can schedule a time for him to meet.

Best Regards,

Sasha Forsen | Public Relations Manager
phone: 402.315.1670 | email: Sasha.Forsen@gpreinc.com

Green Plains Inc.
1811 Aksarben Drive | Omaha, NE 68106

www.gpreinc.com | Facebook | Twitter

CONFIDENTIALITY NOTICE: The information contained in this email, including any attachments, is confidential information and is intended only for use by those to whom it is addressed and may be privileged or otherwise protected. If you are not the intended recipient, any disclosure, copying, printing or use of this information is prohibited. If you received this information in error, please notify Green Plains immediately via fax 402.884.8776 or email at info@gpreinc.com.

ENTITY NOTICE: Green Plains Inc. owns its assets and operates its businesses through various subsidiaries and also seconds its employees to the general partner of its affiliated public company, Green Plains Partners LP. As such, neither the domain name, the signature block or any other entity reference in this email shall imply such employee is working for the entity so identified. Rather, the actions, authorizations or statements made in any such email shall relate to the applicable Green Plains entity that is subject of the contract or other legal document to which the topic relates.

Message

From: Erin Chancellor [Erin.Chancellor@tceq.texas.gov]
Sent: 10/16/2017 7:33:34 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Grace Barr [Grace.Barr@Tceq.Texas.Gov]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: EPA Phone Call with Chairman Shaw

Mandy can give me a call now if that works. Personal Phone / Ex. 6

Erin E. Chancellor

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Monday, October 16, 2017 2:32 PM
To: Erin Chancellor <Erin.Chancellor@tceq.texas.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Grace Barr <Grace.Barr@Tceq.Texas.Gov>
Subject: RE: EPA Phone Call with Chairman Shaw

Hey Erin – Mandy is available now or after 5:00 for brief call and she could better explain to you.

Alex

From: Erin Chancellor [mailto:Erin.Chancellor@tceq.texas.gov]
Sent: Monday, October 16, 2017 2:16 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Grace Barr <Grace.Barr@Tceq.Texas.Gov>
Subject: RE: EPA Phone Call with Chairman Shaw

Hi Mandy,

The Chairman is happy to speak to you today, but I want to make sure he's the best person to talk to in case there are any ex parte issues. Let me know when you have a chance and we can set up a call.

Thanks,

Erin E. Chancellor

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Monday, October 16, 2017 11:38 AM
To: Erin Chancellor <Erin.Chancellor@tceq.texas.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Grace Barr <Grace.Barr@Tceq.Texas.Gov>
Subject: Re: EPA Phone Call with Chairman Shaw

Hey Eric - I am looping in Mandy who can provide more details.

Sent from my iPhone

On Oct 16, 2017, at 12:34 PM, Erin Chancellor <Erin.Chancellor@tceq.texas.gov> wrote:

> Hi Alex,

Is it possible to get a little more information on which petition(s) Mandy wants to talk about? The Chairman does have time today, but I need to figure out if this is going to be about specific permits or permits in general.

Due to Texas ex parte communication laws, the Chairman cannot talk/hear about certain issues until it's presented at an open meeting.

Thank you,

Erin E. Chancellor
Special Counsel to Chairman Bryan Shaw, Ph.D., P.E.
Texas Commission on Environmental Quality
12100 Park 35 Circle, Bldg. F, Austin, Texas 78753
(512) 239-0649
Erin.Chancellor@tceq.texas.gov

From: Grace Barr
Sent: Monday, October 16, 2017 9:18 AM
To: Bryan Shaw <Bryan.Shaw@tceq.texas.gov>; Erin Chancellor <Erin.Chancellor@tceq.texas.gov>
Subject: FW: EPA Phone Call with Chairman Shaw

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Monday, October 16, 2017 9:04 AM
To: Grace Barr <Grace.Barr@Tceq.Texas.Gov>
Subject: EPA Phone Call with Chairman Shaw

Morning Grace,

Does Commissioner Shaw have 15 minutes today to speak with Mandy Gunasekara, EPA Senior Advisor to
the Administrator for Air & Radiation? It would be a preliminary discussion on Title V issues and pending petitions we have received.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

Message

From: Martin, Mary [Mary.Martin@mail.house.gov]
Sent: 9/28/2017 1:07:39 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Hearing Next Wednesday - Air Quality Impacts of Wildfires

FYI.

Mary K. Martin
Deputy Chief Counsel, Energy and Environment
U.S. House Committee on Energy and Commerce
2125 Rayburn House Office Building
(202) 225-2927

FOR IMMEDIATE RELEASE
September 27, 2017

Contact: Press Office
(202) 226-4972

#SubEnvironment to Examine the Impact Wildfires Have on Air Quality

WASHINGTON, DC – The Environment Subcommittee, chaired by Rep. John Shimkus (R-IL), today announced a hearing for Wednesday, October 4, 2017, at 10 a.m. in room 2123 of the Rayburn House Office Building. The hearing is entitled, "Air Quality Impacts of Wildfires: Perspectives of Key Stakeholders."

Considering the devastating and widespread wildfires out West this summer, #SubEnvironment will examine the impacts these wildfires have on air quality and emissions in the affected areas and across the country. Members will also look at how better management of our forests is needed to avoid and minimize catastrophic wildfires. For example, prescribed burns and fuel reduction are important forestry management tools in preventing uncontrolled wildfires, and the resulting air emissions.

"Year after year, catastrophic wildfires rage on federal lands, including parts of my district, and our skies are choked with smoke throughout the West. Air quality issues in my home state continue to rise to dangerous levels because of these fires, forcing cancellations of community events, school closures, and lost tourism dollars," **said full committee Chairman Greg Walden (R-OR)**. "Enough is enough. It's time that decisions about when and how to fight these fires take into account the impact they have on air quality and human health. I'm looking forward to hearing from our panel of witnesses on what our nation can do to better prepare, manage, and fight these fires."

"This subcommittee has been at the forefront of important reforms that improve the environment, the economy, and the public health," **added #SubEnvironment Chairman Shimkus**. "Next week's hearing will provide our members the opportunity to learn more about how uncontrolled forest fires are impacting the quality of the air we breathe and examine potential solutions to mitigate future catastrophic fires."

The Majority Memorandum, witness list, and witness testimony can be found online HERE.

###

PERMALINK

ENERGYCOMMERCE.HOUSE.GOV

This email and any related documents generated or received by the Committee on Energy and Commerce are congressional records and remain subject to congressional control, even if forwarded to an agency in connection with legislative or oversight activities. Any documents created or compiled by an agency in relation to any response to this email or to any related congressional communications are also congressional records and remain subject to congressional control. Accordingly, the aforementioned documents are not "agency records" for purposes of the Freedom of Information Act.

Message

From: Denton, Charles [Charles.Denton@btlaw.com]
Sent: 10/2/2017 4:02:28 PM
To: Pruitt, Scott [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=757bedfd70ca4219b6d8046f5ce5681e-Pruitt, Sco]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Tsirigotis, Peter [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=d19c179f3ccb4fadb48e3ae85563f132-PTSIRIGO]; Barnett, Keith [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=539d3cb498494c49a400212adc19d839-Barnett, Keith]; Storey, Brian [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=bba90f214cbf4f97907a9ea0c5802212-Storey, Bri]; Bowers, Joel [Joel.Bowers@btlaw.com]
Subject: Review of Denial of Clean Air Act Rule Petition
Attachments: Letter to EPA.pdf

Administrator Pruitt—

Attached please find correspondence from the Tile Council of North America, Inc., regarding the Ceramic Tile Manufacturing NESHAP rule reconsideration request.

Thank you for your anticipated prompt attention to this renewed request.

Charlie Denton

VCard | Bio | Dept Info

Charles M. Denton | Partner, Environmental Law Department
Barnes & Thornburg LLP
171 Monroe Avenue N.W., Suite 1000, Grand Rapids, MI 49503-2694
3475 Piedmont Road N.E., Suite 1700, Atlanta, GA 30305-3327

Direct: (616) 742-3974 (616) 742-3974 | Mobile: (616) 481-0462 (616) 481-0462 | Fax: (616) 742-3999

National Tier 1 Ranking for Environmental Law and Environmental Litigation
U.S. News-Best Lawyers® 2017 "Best Law Firms"

Atlanta | Chicago | Dallas | Delaware | Indiana | Los Angeles | Michigan | Minneapolis | Ohio | Washington, D.C.

CONFIDENTIALITY NOTICE: This email and any attachments are for the exclusive and confidential use of the intended recipient. If you are not the intended recipient, please do not read, distribute or take action in reliance upon this message. If you have received this in error, please notify us immediately by return email and promptly delete this message and its attachments from your computer system. We do not waive attorney-client or work product privilege by the transmission of this message.

TCNA
TILE COUNCIL OF NORTH AMERICA, INC.
Website: www.tileusa.com . Literature: literature@tileusa.com

October 2, 2017

The Honorable E. Scott Pruitt, Administrator
U.S. Environmental Protection Agency
Room 3000
William Jefferson Clinton Building
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Review of Denial of Petition for Administrative Reconsideration of the NESHAP for the Clay Ceramics Manufacturing Category

Dear Administrator Pruitt:

The Tile Council of North America, Inc. ("TCNA") respectfully requests that the U.S. Environmental Protection Agency ("EPA" or "Agency") review its prior denial of the TCNA's Petition for Reconsideration of the final agency action entitled, "National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing," published at 80 Fed. Reg. 65470 (Oct. 26, 2015) ("Final Rule").

Established in 1945 as the Tile Council of America, TCNA now represents approximately 240 members of manufacturers of ceramic tile, tile installation material, tile equipment, raw materials, and other tile-related products throughout North America including the tile manufacturers potentially affected by the Final Rule.

Through its public comments to the proposed rule and original Petition for Reconsideration, TCNA identified issues in the Final Rule that threaten the economic viability of many plants and businesses in our industry.

TCNA timely filed its Petition for Reconsideration on December 24, 2015. EPA denied TCNA's petition in a letter dated May 12, 2016 and issued a Federal Register notice of its denial a few days later. 81 Fed. Reg. 31,234 (May 18, 2016).

TCNA's original Petition for Reconsideration outlined significant issues in the Final Rule, including but not limited to:

- CAA Sections 112(c)(1) and 112(d)(1) Do Not Authorize EPA to Promulgate Major Source NESHAPs for the Ceramic Tile Industry Because EPA Has Found There Are No Major Sources in the Industry

TILE COUNCIL OF NORTH AMERICA, INC.
100 Clemson Research Boulevard . Anderson, South Carolina 29625 . Phone: 864-646-8453 . Fax: 864-646-2821

- An EPA Determination Not to Finalize the Ceramic Tile Manufacturing NESHAP Would Not Have Created a "Loophole" Allowing a Future Major Source in this Industry to "Evade Regulation"
- The Existence of Synthetic Area Sources in this Industry Does Not Support Finalization of the Ceramic Tile Manufacturing NESHAP Because Synthetic Area Sources are Not Major Sources
- EPA's Reliance on Method 23 as a Self-Validating Method is a New Position, and Relying Solely on Field Spike Recoveries for that Validation is Scientifically Invalid

Issues raised in TCNA's Petition for Reconsideration are a subset of the issues raised in the judicial Petitions for Review filed, consolidated and still pending before the United States Court of Appeals for the D.C. Circuit.

For all these reasons, TCNA respectfully requests that EPA review its prior denial of TCNA's Petition for Reconsideration, and reevaluate whether the Final Rule should be rescinded or modified.

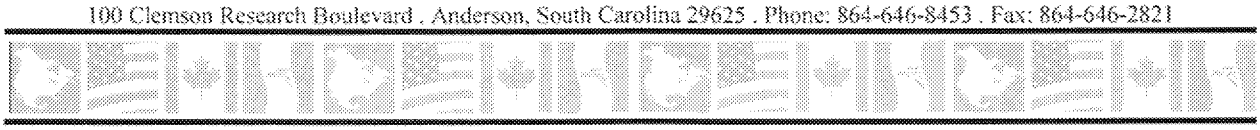
Thank you for your consideration of these important issues. We are ready and willing to work with you to resolve these issues. Please feel free to contact the undersigned or our legal counsel at Barnes & Thornburg LLP if you have questions or need more information.

Sincerely,

Eric Astrachan
President
Tile Council North America

cc: Mandy Gunasekara, OAR
Peter Tsirigotis, OAQPS
Keith Barnett, OAQPS
Brian Storey, OAQPS
Charles Denton, B&T

TILE COUNCIL OF NORTH AMERICA, INC.
100 Clemson Research Boulevard . Anderson, South Carolina 29625 . Phone: 864-646-8453 . Fax: 864-646-2821



Testing Services: testing@tileusa.com . **Literature Orders:** literature@tileusa.com

Message

From: Samantha McDonald [SMcDonald@ipaa.org]
Sent: 10/16/2017 7:17:35 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Lee Fuller [lfuller@ipaa.org]
Subject: FW: Final Agenda IPAA Regulators' Forum Tomorrow
Attachments: 17RF10_10.16 AM.XLS; 172017RegulatorsForum_Agenda.pdf

Mandy,

Thanks again for agreeing to speak at 2017 IPAA's Regulators' Forum. We are looking forward to having you join us. Attached is the list of attendees as well as the final agenda. Lee Fuller on our team will be introducing you.

We have you scheduled from 9:30-10:30AM. The last time I checked with Alex, you had not decided to a powerpoint. If that has changed, let me know ASAP.
The chairs will be setup in a horseshoe-setup with a podium at the opening for you like this:

My cell is 570-244-5113 should you have any last minute questions. I look forward to having you join us!

Kind regards,

Sam

Samantha McDonald
Director of Government Relations
Independent Petroleum Association of America
(202)857-4722 / **Visit IPAA** / **Visit ESA Watch**

IPAA Mtg - Attendee List All Fields

2017 Regulators' Forum - October

Location:

Date: 10/17/2017

Registration	Last Name	First Name	Badge
Non-Member	Dominguez	Alex	ALEX
Non-Member	Franks	Jessica	JESSICA
Staff Registration	Fuller	Lee	LEE
Member	Funk	Marnie	MARNIE
Member	Gainer	Sarah	SARAH
Speaker Registration	Gale	John	JOHN
Member	Garvey	Megan	MEGAN
Staff Registration	Ginsberg	Susan	SUSAN
Speaker Registration	Gunasekara	Mandy	MANDY
Speaker Registration	Hammond	Casey	CASEY
Member	Heneghan	Adell	ADELL
Member	Hoffman	Jennifer	JENNIFER
Member	Johnson	Krista	KRISTA
Member	Kern	Gretchen	GRETCHEN
Staff Registration	Kirby	Neal	NEAL
Member	Kirchoff	Wendy	WENDY
Member	Livanios	Anthony	ANTHONY
Member	Loper	Shea	SHEA
Speaker Registration	Mayberry	Alan	ALAN
Staff Registration	McDonald	Sam	SAM
Cooperating Association	McDonough	Erin	ERIN
Member	McNamara	Olivia	OLIVIA
Member	McNamee	Ashley	ASHLEY
Staff Registration	Miller	Mallori	MALLORI
Staff Registration	Naatz	Dan	DAN
Member	Ready	J. Robert	ROBERT
Member	Schaaff	Lesley	LESLEY
Member	Schrab	Greg	GREG
Member	Schulz	Shane	SHANE
Cooperating Association	Seipel	Penny	PENNY
Member	Sethuraman	Jagadeesan	JAGADEESAN
Speaker Registration	Skipwith	Aurelia	AURELIA
Staff Registration	Thomas	Nikki	NIKKI
Member	Thompson	Bruce	BRUCE
Staff Registration	Ullman	Ryan	RYAN
Speaker Registration	White	Nancy	NANCY
Speaker Registration	Williams	Tim	TIM

Company Name	City	State	Email	Telephone
U.S. Environmental Protection Agency	Washington	DC	domiguez.alexander@epa.gov	
Halliburton	Washington	DC		281-575-3377
IPAA	Washington	DC	lfuller@ipaa.org	202-857-4731
Shell Oil Company	Washington	DC	marnie.funk@shell.com	202-466-1422
Chesapeake Energy Corp.	Oklahoma City	OK	sarah.gainer@chk.com	405-823-8620
PHMSA	Washington	DC		
QEP Resources, Inc.	Denver	CO	megan.garvey@qepres.com	
IPAA	Washington	DC	sginsberg@ipaa.org	202-857-4728
EPA	Washington	DC		202-564-4700
Department of Interior	Washington	DC		202-208-3100
PDC Energy, Inc.	Denver	CO	adell.heneghan@pdce.com	303-860-5800
Huntley & Huntley Inc.	Monroeville	PA	jennifer.hoffman@hhenergyco.com	717-215-7281
Cimarex Energy Co.	Denver	CO	kjohnson@cimarex.com	303-285-4964
Pioneer Natural Resources Co.	Irving	TX	Gretchen.Kern@pxd.com	972-969-3936
IPAA	Washington	DC	nkirby@ipaa.org	202-857-4722
Noble Energy, Inc.	Houston	TX	wendy.kirchoff@nblenergy.com	281-872-2668
U.S. Energy Stream, Inc.	Washington	DC	livanios@usenergystream.com	202-802-8009
Encana Oil & Gas (USA) Inc.	Denver	CO	shea.loper@encana.com	720-876-5812
PHMSA	Washington	DC		
IPAA	Washington	DC	smcdonald@ipaa.org	202-857-4722
Michigan Oil And Gas Association	Lansing	MI	emcdonough@michiganoilandgas.org	517-487-1092
SK Plymouth LLC	Tulsa	OK	omcnamara@skplymouth.com	918-599-1861
Whiting Petroleum Corporation	Denver	CO	ashley.mcnamee@whiting.com	303-837-1661
IPAA	Washington	DC	mmiller@ipaa.org	202-857-4722
IPAA	Washington	DC	dnaatz@ipaa.org	202-857-4739
Concho Resources, Inc.	Midland	TX	rready@concho.com	432-685-4345
Hess Corporation	Washington	DC	lschaaff@hess.com	202-263-1011
SM Energy	Denver	CO	gschrab@sm-energy.com	303-861-8140
QEP Resources, Inc.	Denver	CO	shane.schulz@qepres.com	
Ohio Oil and Gas Association	Columbus	OH	penny@ooga.org	614-824-3901
Whiting Petroleum Corporation	Denver	CO	jagadeesan.sethuraman@whiting.com	303-390-4986
Department of Interior	Washington	DC		202-208-3100
IPAA	Washington	DC	nmcdermott@ipaa.org	202-857-4742
American Exploration & Production Council	Washington	DC	bthompson@axpc.us	202-742-4540
IPAA	Washington	DC	rullman@ipaa.org	202-857-4722
PHMSA	Washington	DC		
Department of Interior	Washington	DC		202-208-3100

Tuesday, October 17 | 9:00 AM – 3:00 PM
NAHB Building | The Auditorium | 1st Floor

9:00 AM	Coffee & Pastries
9:15 AM	IPAA Opening Remarks
9:30 AM - 10:30 AM	Mandy Gunasekara, Senior Policy Advisor, Office of the Administrator EPA
10:30 AM - 10:45 AM	Break
10:45 AM - 11:30 AM	Aurelia Skipwith, Deputy Assistant Secretary Fish, Wildlife and Parks U.S. Department of the Interior
11:45 AM - 12:15 PM	Timothy Williams, Deputy Director External Affairs U.S. Department of the Interior
12:15 PM - 1:00 PM	Networking Lunch
1:00 PM - 1:30 PM	Casey Hammond, Office of the Deputy Assistant Secretary for Land and Minerals Management U.S. Department of the Interior
1:30 PM - 2:30 PM	**PHMSA** John Gale, Director of Standards and Rulemaking Alan Mayberry, Associate Administrator for Pipeline Safety Nancy White, Director of Policy and Programs
2:30 PM	Group Discussion/Closing Remarks
3:00 PM	Adjourn

Message

From: Zelermyer, Salo [Salo.Zelermyer@valero.com]
Sent: 9/30/2017 4:30:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Hey

Stay strong. The cavalry is mobilizing.

Sent from my iPhone

> On Sep 29, 2017, at 9:50 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>
> Thank you for the note. Needed and very much appreciated
>
> Sent from my iPhone
>
>> On Sep 29, 2017, at 9:45 PM, Zelermyer, Salo <Salo.Zelermyer@valero.com> wrote:
>>
>> Hang in there. You're doing a great job. We'll get through this!
>>
>> Best
>>
>> Salo
>>
>> Sent from my iPhone

Message

From: Traylor, Patrick [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=B6D06C6B766C4B4B8BFDF6B0FEA4B998-TRAYLOR, PA]
Sent: 9/27/2017 4:03:26 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Jonathan E. Missner [JMissner@steinmitchell.com]
Subject: RE: E-Connect

Mandy, thank you.

Jonathan, I look forward to meeting you.

Patrick Traylor
Deputy Assistant Administrator
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
(202) 564-5238 (office)
Personal Phone / Ex. 6 (cell)

From: Gunasekara, Mandy
Sent: Wednesday, September 27, 2017 11:30 AM
To: Jonathan E. Missner <JMissner@steinmitchell.com>
Cc: Traylor, Patrick <traylor.patrick@epa.gov>
Subject: E-Connect

Jonathan,
Great chatting with you this morning. I could not find Chris's email address so please loop him in. As promised, I'm connecting you with Patrick Traylor (cc'd) who is the Deputy in OECA and will be good to touch base with.

Patrick,
Jonathan (and Chris once looped in) works for the Specialty Equipment Manufacturers Association (SEMA) and have some questions regarding related enforcement policies. They have been working closely with Congress on the RPM Act, so much of the discussion will be relative to that effort and some back-and-forth they received from OECA.

I'll leave to you both to find a time to connect. Let me know if I can help.
Best,
Mandy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 10/6/2017 3:47:01 PM
To: Susan Butler [sbutler@capitolresourcesllc.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: small refinery hardship scoring process

Hey Susan – Could you give me a call when you have a moment? We spoke with DOE yesterday and I just have a few questions on logistics I would like to briefly discuss. My work cell is Personal Phone / Ex. 6

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Susan Butler [mailto:sbutler@capitolresourcesllc.com]
Sent: Wednesday, October 4, 2017 10:46 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: small refinery hardship scoring process

Good morning! I want to follow up on your offer to the coalition to host a joint meeting with DOE re: the small refinery hardship scoring process. It would be great if we could do that fairly soon as the next cycle will soon be upon us. I've attached the small refinery coalition's suggestions which we believe would streamline the process and make it more objective.

Please let me know if there are any meetings you think we need to have in advance of a joint agency meeting. Many thanks, Susan

Susan Butler
Capitol Resources LLC
915 Prince Street
Alexandria, VA 22314
(703)739-5860 (office)
(703)298-2826 (cell)

Message

From: Cox, Ed (Hatch) [Ed_Cox@hatch.senate.gov]
Sent: 9/28/2017 8:34:31 PM
To: Cox, Ed (Hatch) [Ed_Cox@hatch.senate.gov]
Subject: Moving On

Colleagues,

As some of you may know, today is my last day with Senator Orrin Hatch. Beginning next week, I will be moving on to a new opportunity off of the hill. Over the last 5 years I have had the honor of advising Senator Hatch on natural resource and environment policy. It goes without saying, but it has truly been a rewarding experience and privilege to work for my home state as well as one of the great Members of the United States Senate.

Furthermore, I truly appreciate working with all of you and the great counsel and advice you've given me during my time with the Senator. I couldn't have done it without the great support of so many of my friends both here in the Senate and back in the state.

For the time being, if you need assistance from the Hatch office for energy and natural resource policy issues please contact Romel Nicholas (romel_nicholas@hatch.senate.gov) or John Tanner (john_tanner@hatch.senate.gov). You'll be in good hands.

I would like to stay in touch. Please find my contact information below:

Email:
Cell: 8 **Personal Phone / Ex. 6**

It's been a pleasure and I hope we continue to have opportunities to work together in my future capacity.

Best,

Ed

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/13/2017 2:36:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Draft RH SIP and supporting docs part 2
Attachments: 7_App_A_Bailey_McClellan.pdf; 8_B1_3_26_2007_BART_Domtar.pdf; 9_B2_5_16_14_Sup_BART_Deter.pdf; 11_C_Lake_Catherine.pdf

Part 2.

Stuart Spencer
Associate Director- Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
Ph. # (501) 682-0750
Fax # (501) 682-0880
E-mail: SPENCER@adeq.state.ar.us
Web: http://www.adeq.state.ar.us

This e-mail and any files transmitted with it are the property of the Arkansas Department of Environmental Quality, and are intended solely for the use of the individual or entity to whom this email is addressed. If you are not the named recipient(s) or otherwise have reason to believe that you have received this message in error, please notify the sender at (501) 682-0750 and delete this message immediately from your computer. Any other use, retention, dissemination, forwarding, printing or copying of this email is strictly prohibited.

Entergy

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-13-052

June 25, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – Lake Catherine Plant
Revised BART Five-Factor Analysis
Permit No. 1717-AOP-R5, AFIN 30-00011

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for Unit 4 located at the Entergy Arkansas, Inc – Lake Catherine Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the initial FFA which was submitted on March 4, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson

G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

REVISED BART FIVE FACTOR ANALYSIS
LAKE CATHERINE STEAM ELECTRIC STATION
MALVERN, ARKANSAS (AFIN 30-00011)

Prepared By:

TRINITY CONSULTANTS, INC.
201 NW 63rd St., Suite 220
Oklahoma City, Oklahoma 73116
(405) 848-3724

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

ENTERGY SERVICES, INC.
425 West Capitol Avenue
Little Rock, Arkansas 77203
(501) 377-4000

Trinity Project No. 123701.0053

June 2013

Entergy.
THE POWER OF PEOPLE*

Trinity Consultants

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INTRODUCTION AND BACKGROUND 2-1

3. MODELING METHODOLOGIES AND PROCEDURES 3-1
3.1 CALMET AND CALPUFF 3-1
3.2 CALPOST 3-1

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT 4-1
4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES 4-1
4.2 BASELINE VISIBILITY IMPAIRMENT 4-1

5. SO_2 BART EVALUATION 5-1

6. NO_X BART EVALUATION 6-1
6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES 6-1
6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES 6-1
6.2.1 COMBUSTION CONTROLS 6-2
6.2.1.1 Burners Out of Service (BOOS) 6-2
6.2.1.2 Flue Gas Recirculation (FGR) 6-2
6.2.1.3 Separated Overfire Air (SOFA) 6-2
6.2.1.4 Low NO_X Burners 6-2
6.2.2 POST COMBUSTION CONTROLS 6-3
6.2.2.1 Selective Catalytic Reduction (SCR) 6-3
6.2.2.2 Selective Non-Catalytic Reduction (SNCR) 6-3
6.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS 6-4
6.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS 6-4
6.4.1 COST OF COMPLIANCE 6-4
6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS 6-8
6.4.3 REMAINING USEFUL LIFE 6-8
6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS 6-8
6.6 PROPOSED BART FOR NO_X 6-14

7. PM_{10} BART EVALUATION 7-1

APPENDIX A (SO_2 AND NO_X CONTROL COST CALCULATIONS)

APPENDIX B (CALMET MODELING PROTOCOL)

APPENDIX C (CEMS DATA FROM CAMD FOR 2001 TO 2003)

APPENDIX D (SARGENT & LUNDY NO_X CONTROL TECHNOLOGY STUDY)

LIST OF TABLES

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO UNIT 4 1-1

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION 3-3

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS 3-3

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS 3-3

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS 3-3

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS) 4-1

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO LAKE CATHERINE, UNIT 4 BY POLLUTANT 4-2

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR UNIT 4 6-1

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES 6-4

TABLE 6-3. LAKE CATHERINE UNIT 4 CAPACITY FACTORS 6-5

TABLE 6-4. SUMMARY OF COST EFFECTIVENESS FOR UNIT 4 NO_X CONTROLS 6-7

TABLE 6-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT BOOS FOR NO_X CONTROL 6-10

TABLE 6-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA FOR NO_X CONTROL 6-10

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SNCR FOR NO_X CONTROL 6-10

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SCR FOR NO_X CONTROL 6-10

TABLE 6-9. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON UNIT 4 (2001-2003) 6-11

TABLE 6-10. INCREMENTAL COST EFFECTIVENESS FOR UNIT 4 WITH CLASS I AREA IMPROVEMENT (2001-2003) 6-13

1. EXECUTIVE SUMMARY

This report is a revision to the "BART Five Factor Analysis" submitted to ADEQ on March 4, 2013 and is being submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.'s (Entergy's) BART-affected electric generating unit (EGU), Unit 4 at the Lake Catherine plant including revisions made in response to EPA's comments and suggestions on the previous submittal. The BART determination for each pollutant has not changed.

Unit 4 is a tangentially-fired boiler with a nominal net power rating of 558 MW and a nominal heat input capacity of 5,850 million British thermal units per hour (MMBtu/hr) that is permitted to burn natural gas and No. 6 fuel oil. Entergy does not project to burn fuel oil at Lake Catherine Unit 4 in the foreseeable future, so emissions from fuel oil are not considered in this analysis. If conditions change such that it becomes economic to burn fuel oil, a five factor analysis will be submitted for approval in the State Implementation Plan (SIP). The combustion of fuel oil would not occur until final SIP approval.

BART determinations for SO_2 and PM_{10} based on the use of natural gas were approved in EPA's March 12, 2012 final rule. The determinations result in no SO_2 or PM_{10} controls needed during natural gas combustion.

Based on modeling performed for this analysis, combined emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from Lake Catherine Unit 4 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) to visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[1]. The contributions of the SO_2 and PM_{10} emissions to the visibility impairment are negligible when compared to the contribution of NO_X.

A summary of the existing visibility impairment attributable to the boiler based on the default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on recent modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of stack testing, Continuous Emission Monitoring System (CEMS) data as reported to EPA's Clean Air Markets Database (CAMD), and AP-42 emission factors as further described in Section 4 of this report.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO UNIT 4

CACR		UPBU		HERC		MING	
98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
1.371	80	0.532	21	0.387	8	0.429	7

[1] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ's) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

Trinity used the EPA's BART guidelines in 40 CFR Part 51[2] to determine BART for Unit 4. Specifically, Trinity conducted a five-step analysis to determine BART for NO_X that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts.

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.24 lb/MMBtu through the installation and use of Burners Out of Service (BOOS) represents BART.[3]

[2] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[3] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at Unit 4. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[4] The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant;
(2) Began operation between August 7, 1962, and August 7, 1977; and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[5] Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *...an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by... [a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

---

[4] The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308.

[5] The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA's 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

1. Existing controls
2. Cost of controls
3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts.

A BART determination should be made for each visibility-affecting pollutant (VAP) by following the five steps listed above for each VAP.

Unit 4 meets the three BART-eligibility criteria described above, and the existing visibility impairment attributable to the boiler is greater than 0.5 Δdv in at least one Class I area. Thus, Unit 4 is subject to BART. Details of the existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by the boiler include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]).

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG)[6].

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI\,(\text{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to

[6] The 2010 FLAG guidance, which was issued in draft form on July 8, 2008, and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta dv = 10 * \ln\left[\frac{b_{ext,\ background} + b_{ext,\ source}}{b_{ext,\ background}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[NH_4(SO_4)_2]_{Small} + 4.8 f_L(RH)[NH_4(SO_4)_2]_{Large} + \\ 2.4 f_S(RH)[NH_4NO_3]_{Small} + 5.1 f_L(RH)[NH_4NO_3]_{Large} + \\ 2.8[OC]_{Small} + 6.1[OC]_{Large} + 10[EC] + 1[PMF] + 0.6[PMC] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[NO_2] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ ($\mu g/m^3$)	NH_4NO_3 ($\mu g/m^3$)	OM ($\mu g/m^3$)	EC ($\mu g/m^3$)	Soil ($\mu g/m^3$)	CM ($\mu g/m^3$)	Sea Salt ($\mu g/m^3$)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. $F_L(RH)$ LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. $F_S(RH)$ SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. $F_{SS}(RH)$ SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e., baseline) visibility impairment attributable to Unit 4 based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS).[7] Please note that CEMS data from these years is representative of burning only natural gas.

The emission rates for the PM_{10} species reflect the breakdown of the filterable and condensable PM_{10} determined from AP-42 Table 1.4-2 *Combustion of Natural Gas.* All filterable PM was assumed to be elemental carbon, as this is the assumption that the National Park Service (NPS) uses for filterable PM_{10} from natural gas fired combustion turbines, and the NPS does not have a speciation analysis specific to gas fired boilers. All of the condensable PM was assumed to be SOA, except for a small fraction of the condensable PM that was estimated to be SO_4. One-third of the estimated SO_2 emissions were separated and adjusted for differences in molecular weight to represent SO_4 emissions. This essentially double counts some of the fuel sulfur based emissions as SO_2 but also as SO_4. Since pipeline natural gas contains very little sulfur, both the SO_2 and SO_4 emission rates are very low.

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Unit	SO_2[8] (lb/hr)	NO_X[9] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 4	3.1	2,456.4	44.3	1.5	0.0	0.0	31.8	11.0

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to Unit 4 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model. Table 4-2 provides a summary of the modeled visibility impairment attributable to Unit 4 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Table 4-2 the maximum

[7] *See* Appendix C

[8] The SO_2 hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 74 lb/day. *See* Appendix C.

[9] The NO_x hourly rate was derived from EPA's CAMD. The 2001-2003 max daily rate was 58,954 lb/day. *See* Appendix C.

impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO LAKE CATHERINE, UNIT 4 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.480	1.371	31	0.49	85.13	0.00	8.55
2002	3.318	0.909	21	0.31	92.53	0.00	4.18
2003	3.276	1.233	28	0.43	85.66	0.00	7.76
Upper Buffalo Wilderness							
2001	1.478	0.489	7	0.33	89.54	0.00	5.99
2002	0.916	0.532	9	0.22	96.29	0.00	1.26
2003	2.044	0.412	5	0.21	97.36	0.00	0.30
Hercules Glades Wilderness							
2001	0.760	0.387	4	0.30	91.12	0.00	4.92
2002	1.016	0.313	2	0.39	88.73	0.00	6.08
2003	0.881	0.311	2	0.38	93.27	0.00	2.57
Mingo Wilderness							
2001	0.511	0.237	1	0.30	92.55	0.00	3.17
2002	0.763	0.429	5	0.32	96.25	0.00	0.44
2003	0.516	0.214	1	0.18	98.08	0.00	0.10

5. SO_2 BART EVALUATION

A BART determination for SO_2 based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no SO_2 controls needed during natural gas combustion.[10]

[10] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

6. NO_X BART EVALUATION

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has lead to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as Unit 4, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including Burners Out of Service (BOOS), flue gas recirculation (FGR), overfire air / separated overfire air (SOFA), and Low NO_x Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR UNIT 4

NO_X Control Technologies	
Combustion Controls	Burners Out of Service (BOOS) Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_x Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

6.2.1 COMBUSTION CONTROLS

6.2.1.1 BURNERS OUT OF SERVICE (BOOS)

BOOS is a staged combustion technique whereby fuel is introduced though operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners. Additional air is then supplied to the non-operational burners to complete combustion. By removing fuel from certain zones, the temperature is reduced, and the production of thermal NO_X is also reduced. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with BOOS is 0.24 lb/MMBtu.[11] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.2 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the estimated controlled NO_X level for Unit 4 operating with FGR is 0.19 lb/MMBtu.[12] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.3 SEPARATED OVERFIRE AIR (SOFA)

SOFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. When operated without additional controls, SOFA results in estimated NO_X emissions for gas fired boilers of 0.2-0.4 lb/MMBtu.[13] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.1.4 LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[14] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is

---

[11] Sargent & Lundy May 16, 2013 NOx Control Technology Cost and Performance Study (S&L 2013 Study).

[12] *Id.*

[13] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

[14] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When operated without additional controls, LNB results in estimated NO_X emissions for gas fired boilers of approximately 0.25 lb/MMBtu.[15] When combined with SOFA, the estimated NO_X control level is 0.19 lb/MMBtu.[16] LNB systems are technically feasible for the control of NO_X from Unit 4.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with SOFA and LNB, the estimated NO_X control level is 0.03 lb/MMBtu.[17] This control is a technically feasible option for the control of NO_X from Unit 4.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with SOFA and LNB, the estimated NO_X

[15] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.
[16] S&L 2013 Study.
[17] *Id.*

control level is 0.14 lb/MMBtu.[18] This control is being evaluated as a technically feasible option for the control of NO_X from Unit 4; however this technology is not adaptable to all gas-fired boilers.

6.3 Rank of Technically Feasible NO_X Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section for Unit 4.

Table 6-2. Control Effectiveness of Technically Feasible NO_X Control Technologies

Control Technology	Estimated Controlled Level for Unit 4 (lb/MMBtu)
SOFA	0.30
LNB	0.25
BOOS	0.24
LNB/SOFA OR FGR	0.19
LNB/SOFA + SNCR	0.14
LNB/SOFA + SCR	0.03

6.4 Evaluation of Impacts for Feasible NO_X Controls

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1 Cost of Compliance

The capital costs, operating costs, and cost effectiveness of BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR were estimated for the cost analysis. Since FGR results in the same controlled emission level as LNB/SOFA but at a higher cost[19], FGR is not considered further in the analysis.

[18] S&L 2013 Study.
[19] *Id.*

Control Costs

Control costs were calculated using cost estimates developed by Sargent and Lundy. The capital costs were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs.

The capital and operating cost estimates are provided in Appendix A of this report.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rate was calculated using the baseline emission level of 0.48 lb/MMBtu and an annual heat input reflecting a ten percent capacity factor.[20]

EPA states in the BART guidelines that *"The baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source."* While the average annual capacity factor for Unit 4 from 2001-2003, which are the baseline years from which the peak daily NO_X emission rate was determined as described in Section 4 of this report, was approximately 20 percent, Entergy anticipates that future utilization of Unit 4 will remain in the range of 10 percent, which is consistent with the recent operating history of the unit.

Table 6-3 below illustrates the annual capacity factor values for Unit 4 over the past ten years (2003-2012). Typical utilization of this unit has been less than 5 percent on an annual basis. Utilization in 2012 was slightly higher than 10 percent due to anomalous grid reliability issues which resulted in a need for greater utilization. These issues are not expected to arise in future years and future annual capacity factors are expected to be comparable to those experienced by the unit in 2003-2011. EPA has stated that they agree that the unit has historically operated at less than a 10 percent capacity factor and that a source may calculate baseline emissions based on a continuation of past practice.[21] A 10 percent capacity factor has been used for this analysis as a conservative estimate.

TABLE 6-3. LAKE CATHERINE UNIT 4 CAPACITY FACTORS

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
10.4	3.2	4.2	0.5	0.7	2.7	3.0	3.1	2.3	12.8

The controlled annual emission rates were based on lb/MMBtu levels believed to be achievable from the control technologies multiplied by the annual heat input. The annual heat input used to calculate the annual controlled emission rates was the same heat input that was used to calculate baseline annual emissions.

[20] The annual heat input reflecting a 10% annual capacity factor is 5,124,600 MMBtu/yr (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr).

[21] 77 Fed. Reg. 14641.

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analyses was also performed to show the incremental increase in the cost of controls when compared to BOOS. The costs effectiveness analysis is summarized in Table 6-4.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of NO_X removed based on the use of combustion control technology.[22] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[23]

Table 6-4 indicates that the cost effectiveness of BOOS is approximately $150 per ton of NO_X removed. Further, the incremental cost effectiveness of LNB/SOFA over BOOS is approximately $9,000/ton, while the incremental cost of LNB/SOFA/SNCR over LNB/SOFA is approximately $17,000/ton and the incremental cost LNB/SOFA/SCR over LNB/SOFA is approximately $14,000/ton.

Table 6-4 also summarizes the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. Details of the post-control modeling results are provided later in Section 6.5, but this summary is presented here for convenience. As Table 6-4 clearly shows, BOOS results in over 0.5 Δdv of visibility improvement when compared the baseline visibility impairment. While LNB/SOFA, LNB/SOFA/SNCR, and LNB/SOFA/SCR offer some additional visibility improvement over BOOS, up to a maximum of 0.672 Δdv of additional improvement for LNB/SOFA/SCR, the very high incremental costs when compared to BOOS cannot be justified.

---

[22] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.) 77 Fed. Reg. 39134-39135 (July 6, 2005).

[23] *Id.*

TABLE 6-4. SUMMARY OF COST EFFECTIVENESS FOR UNIT 4 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost[3]	Incremental Visbility Improvement [2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
BOOS	1,236	0.24	5,124,600	618	618	893,000	71,964	21,000	0	92,964	150	-	0.536
LNB/SOFA	1,236	0.19	5,124,600	495	742	11,845,025	954,548	210,000	19,034	1,183,582	1,596	8,822	0.152
LNB/OFA/SNCR	1,236	0.14	5,124,600	371	865	29,295,494	2,360,819	489,000	462,000	3,311,819	3,827	17,214	0.306
LNB/OFA/SCR	1,236	0.03	5,124,600	77	1159	79,152,952	6,378,652	568,000	268,000	7,214,652	6,223	14,440	0.672

1. The annual heat input reflects a 10% annual capacity factor (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr)

2. The incremental visibility improvement for BOOS is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Table 6-9). The incremental visibility improvement for LNB/OFA, LNB/OFA/SNCR, and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/OFA, LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from BOOS (See Table 6-9).

3. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-4, SCR and SNCR systems are capable of achieving additional NO_X reductions when compared to combustion controls such as BOOS, LNB, or SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of Unit 4 is sufficiently long such that it does not affect the BART analysis.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with BOOS, LNB/SOFA, LNB/SOFA/SNCR, and

LNB/SOFA/SCR. Section 4 of this report documented the existing visibility impairment attributable to Unit 4. In order to assess the visibility improvement associated with BOOS, LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with BOOS is 0.24 lb/MMBtu; the controlled emission level associated with an LNB/SOFA system is 0.19 lb/MMBtu; the controlled emission level associated with an LNB/SOFA/SNCR system is 0.14 lb/MMBtu, and the controlled emission level associated with an LNB/SOFA/SCR system is 0.03 lb/MMBtu. These levels were multiplied by the maximum heat input (5,850 MMBtu/hr) to derive hourly the hourly emission rates used in the modeling.

Tables 6-5 through 6-8 summarize the NO_X emission rates that were modeled to reflect the BOOS, LNB/SOFA, LNB/SOFA/SNCR and LNB/SOFA/SCR control options. The emission rates for the other pollutants shown in Tables 6-5 through 6-8 are the same as in the baseline modeling.

TABLE 6-5. SUMMARY OF EMISSION RATES MODELED TO REFLECT BOOS FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,404.0	0.0	0.0	31.8	11.0	44.3

TABLE 6-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	1,111.5	0.0	0.0	31.8	11.0	44.3

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SNCR FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	819.0	0.0	0.0	31.8	11.0	44.3

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/SOFA + SCR FOR NO_X CONTROL

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
Unit 4	3.1	1.5	175.5	0.0	0.0	31.8	11.0	44.3

Table 6-9 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on Unit 4 in all affected Class I areas, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-9. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON UNIT 4 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	3.480	1.371	80	2.044	0.532	21	1.016	0.387	8	0.763	0.429	7
BOOS	2.154	0.835	37	1.232	0.307	11	0.6	0.229	2	0.447	0.253	0
Post Control Improvement	*1.326*	*0.536*	*43*	*0.812*	*0.225*	*10*	*0.416*	*0.158*	*6*	*0.316*	*0.176*	*7*
LNB/SOFA	1.759	0.683	28	0.996	0.25	9	0.482	0.185	0	0.358	0.204	0
Incremental Post Control Improvement over BOOS	*0.395*	*0.152*	*9*	*0.236*	*0.057*	*2*	*0.118*	*0.044*	*2*	*0.089*	*0.049*	*0*
LNB/SOFA/SNCR	1.349	0.529	16	0.755	0.193	4	0.362	0.141	0	0.268	0.154	0
Incremental Post Control Improvement over BOOS	*0.805*	*0.306*	*21*	*0.477*	*0.114*	*7*	*0.238*	*0.088*	*2*	*0.179*	*0.099*	*0*
LNB/SOFA/SCR	0.452	0.163	0	0.211	0.057	0	0.101	0.043	0	0.082	0.042	0
Incremental Post Control Improvement over BOOS	*1.702*	*0.672*	*37*	*1.021*	*0.25*	*11*	*0.499*	*0.186*	*2*	*0.365*	*0.211*	*0*

†The visibility improvement shown in the table has been calculated from 98th percentile baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled 98th percentile impacts shown in the table, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 6-9, based on visibility predictions from the CALPUFF modeling system, the operation of a BOOS will result in up to a 0.536 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to Unit 4. This visibility improvement increases by 0.152 Δdv for LNB/SOFA (0.835-0.683 = 0.152), 0.306 Δdv for LNB/SOFA/SNCR (0.835-0.529 = 0.306), and 0.672 Δdv for LNB/SOFA/SCR (.835-0.163 = 0.672).

For convenience, Table 6-10 provides a condensed summary of these predicted improvements alongside the estimated control costs. The incremental visibility benefit of going from BOOS to either LNB/SOFA, LNB/SOFA/SCNR or LNB/SOFA/SCR is clearly not justified by the high incremental cost difference. The control technologies are very expensive from an initial capital investment and prohibitively more expensive from an incremental cost effectiveness standpoint than BOOS.

TABLE 6-10. INCREMENTAL COST EFFECTIVENESS FOR UNIT 4 WITH CLASS I AREA IMPROVEMENT (2001-2003)

Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost[1] ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv
BOOS	0.24	50%	618	893,000	92,964	150	-	Caney Creek	1.371	0.835	0.536	80	37
								Hercules-Glades	0.387	0.229	0.158	8	2
								Mingo	0.429	0.253	0.176	7	0
								Upper Buffalo	0.532	0.307	0.225	21	11
LNB/SOFA	0.19	60%	742	11,845,025	1,183,582	1,596	8,822	Caney Creek	1.371	0.683	0.688	80	28
								Hercules-Glades	0.387	0.185	0.202	8	0
								Mingo	0.429	0.204	0.225	7	0
								Upper Buffalo	0.532	0.250	0.282	21	9
LNB/SOFA + SNCR	0.14	70%	865	29,295,494	3,311,819	3,827	17,214	Caney Creek	1.371	0.529	0.842	80	16
								Hercules-Glades	0.387	0.141	0.246	8	0
								Mingo	0.429	0.154	0.275	7	0
								Upper Buffalo	0.532	0.193	0.339	21	4
LNB/SOFA + SCR	0.03	94%	1,159	79,152,952	7,214,652	6,223	14,440	Caney Creek	1.371	0.163	1.208	80	0
								Hercules-Glades	0.387	0.043	0.344	8	0
								Mingo	0.429	0.042	0.387	7	0
								Upper Buffalo	0.532	0.057	0.475	21	0

1. The incremental cost for LNB/SOFA is calculated in comparison to BOOS while the incremental costs for LNB/SOFA + SNCR and LNB/SOFA + SCR are calculated in comparison to LNB/SOFA alone.

6.6 PROPOSED BART FOR NO_X

Entergy proposes a BART emission rate of 0.24 lb/MMBtu on a 30-day rolling average basis, achievable through use of BOOS at Unit 4.[24]

[24] If CSAPR is upheld and implemented in Arkansas, Entergy will rely on CSAPR to satisfy its regional haze obligations at Lake Catherine. If CSAPR is vacated and CAIR remains in effect, EPA's prior determination that the reductions provided under CAIR's seasonal NO_X trading program provide greater visibility improvements than BART should allow Entergy to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.

7. PM_{10} BART EVALUATION

A BART determination for PM_{10} based on the use of natural gas was approved in EPA's March 12, 2012, final rule. The determination results in no PM_{10} controls needed during natural gas combustion.[25]

[25] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

APPENDIX A

CONTROL COST CALCULATIONS

BOOS Capital and O&M Cost Estimate	
Operational Data	
N/A	
Capital Cost	
Implementation Cost[1]	893,000
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	21,000
Variable O&M Costs[4]	0
Annualized Implementation Cost	71,964
Total Annual Costs	92,964

1: It is anticipated that BOOS can be implemented on the unit without any capital expenditures. The one-time costs associated with BOOS implementation would instead be incorporated into the facility's O&M budget for the fiscal year. In order to provide an apples-to-apples comparison with the other NOx control options, these one-time additional O&M costs were treated as if the cost were a capital expenditure. This cost is is based the Sargent & Lundy 5/16/2013 NOx Control Technology Cost and Performance Study.

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for BOOS is based on the fixed O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for BOOS is based on the variable O&M cost estimate for BOOS as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

LNB-SOFA Capital and O&M Cost Estimate

Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	11,845,025
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs	
Fixed O&M Costs[3]	210,000
Variable O&M Costs[4]	19,034
Annualized Capital Cost	954,548
Total Annual Costs	1,183,582

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($8,762,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $751,978), and cost for AFUDC (estimated by Entergy to be $584,184) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA is based on the fixed O&M cost estimate for LNB/OFA as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimate for LNB/OFA is based on an equation documented in the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D as shown below.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appedix D

LNB-OFA + SNCR Capital and O&M Cost Estimate	
Operational Data	
Maximum HI (MMBtu/hr)	5850
Average Annual Operating Hours, 2009-2011	1205
Capital Cost	
Installed Capital Cost[1]	29,295,494
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	489,000
Variable O&M Costs	462,000
Annualized Capital Cost	2,360,819
Total Annual Costs	3,311,819

1: The installed capital cost estimate for LNB/OFA + SNCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($24,269,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $1,821,939), and cost for AFUDC (estimated by Entergy to be $1,457,962 for each unit)
.

2: CRF = [I x(1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimate for LNB/OFA + SNCR is based on the fixed O&M cost estimate for LNB/OFA + SNCR as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-OFA + SCR Capital and O&M Cost Estimate	
Operational Data	
Maximum HI (MMBtu/hr)	5850
Annual Operating Hours, 2009-2011	1205
Capital Costs[1]	
Installed Capital Cost	79,152,952
Capital Recovery Factor (CRF)[2]	0.08
Annual Costs[3]	
Fixed O&M Costs	568,000
Variable O&M Costs	268,000
Annualized Capital Cost	6,378,652
Total Annual Costs	7,214,652

1: The installed capital cost estimate for LNB/OFA + SCR is based on the installed capital cost estimate provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study ($68,349,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $387,500), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,634,363), cost for capital suspense (estimated by Entergy to be $4,888,377), and cost for AFUDC (estimated by Entergy to be $3,956,212) .

2: CRF = [I x(1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: All O&M cost estimateswere provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

APPENDIX C

CEMS DATA FROM CAMD FOR 2001 TO 2003

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

January 23, 2008

Project 083701.0004

TABLE OF CONTENTS

1. INTRODUCTION 1-1
1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND 1-1
1.2 OBJECTIVE 1-2
1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS 1-2

2. CALPUFF MODEL SYSTEM 2-1
2.1 MODEL VERSIONS 2-1
2.2 MODELING DOMAIN 2-1

3. CALMET 3-1
3.1 GEOPHYSICAL DATA 3-1
3.1.1 TERRAIN DATA 3-1
3.1.2 LAND USE DATA 3-2
3.1.3 COMPILING TERRAIN AND LAND USE DATA 3-3
3.2 METEOROLOGICAL DATA 3-3
3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA 3-3
3.2.2 SURFACE METEOROLOGICAL DATA 3-4
3.2.3 UPPER AIR METEOROLOGICAL DATA 3-5
3.2.4 PRECIPITATION METEOROLOGICAL DATA 3-6
3.2.5 BUOY METEOROLOGICAL DATA 3-7
3.3 CALMET CONTROL PARAMETERS 3-8
3.3.1 VERTICAL METEOROLOGICAL PROFILE 3-8
3.3.2 INFLUENCES OF OBSERVATIONS 3-9

APPENDIX A- METEOROLOGICAL STATIONS

APPENDIX B – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 5.8)

APPENDIX C – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 6)

LIST OF TABLES

TABLE 1-1. BART-ELIGIBLE SOURCES 1-2

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS 1-2

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS 2-1

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN 3-9

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS A-1

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS A-5

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS A-6

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS A-14

LIST OF FIGURES

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS 1-3

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN 2-2

FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA 3-2

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA 3-3

FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS 3-5

FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS 3-6

FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS 3-7

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS 3-8

1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

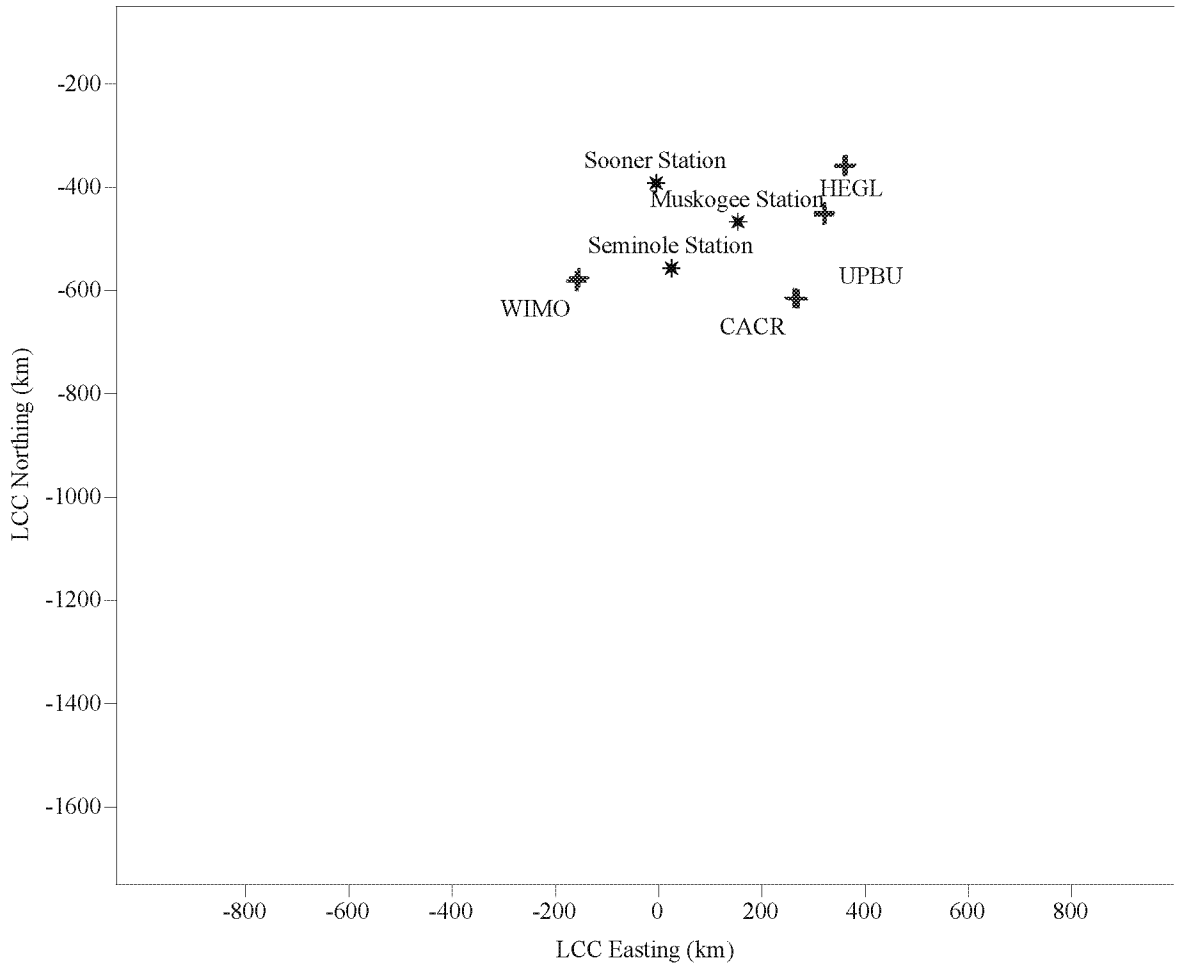
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

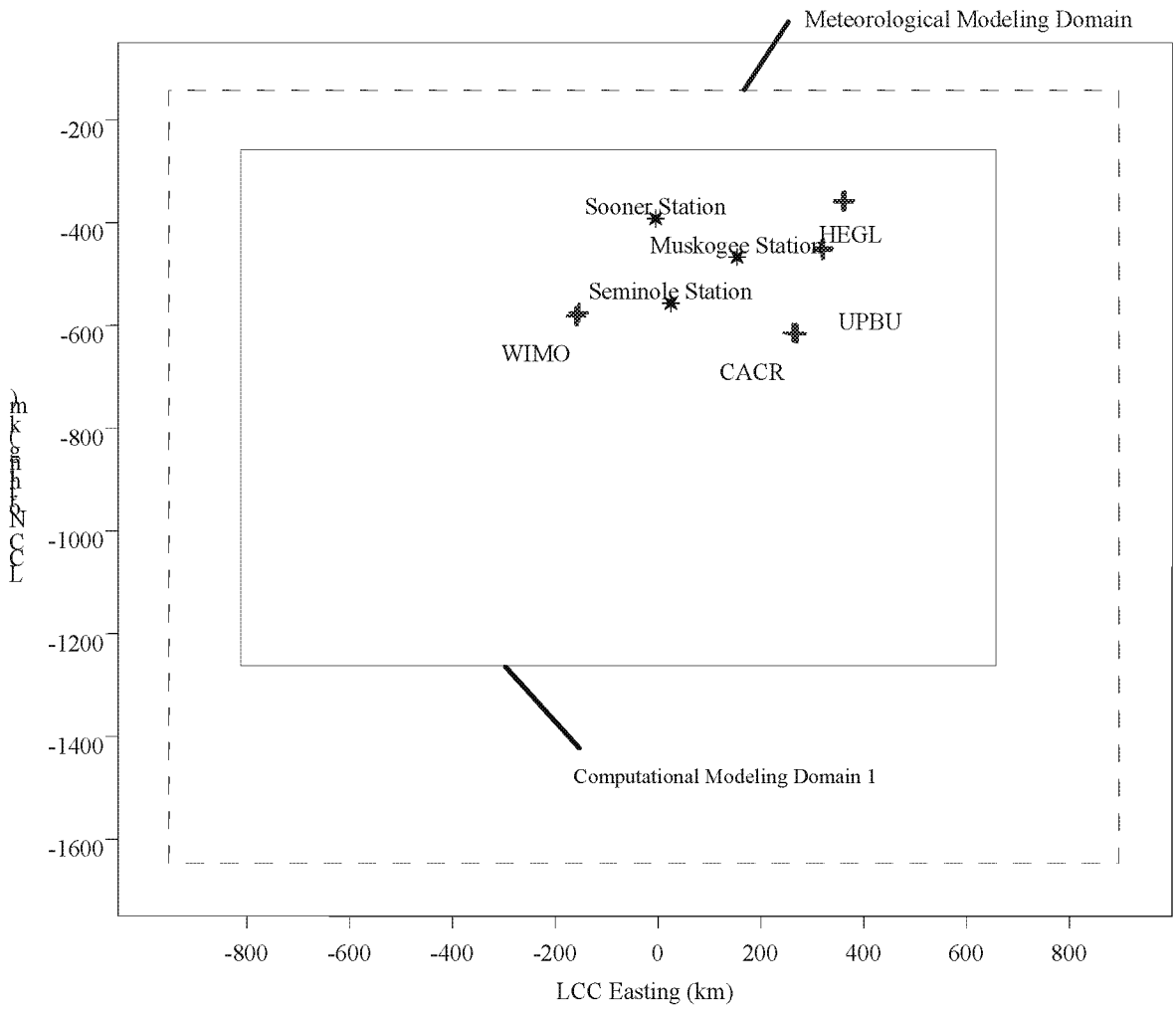
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



Class I Areas

3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

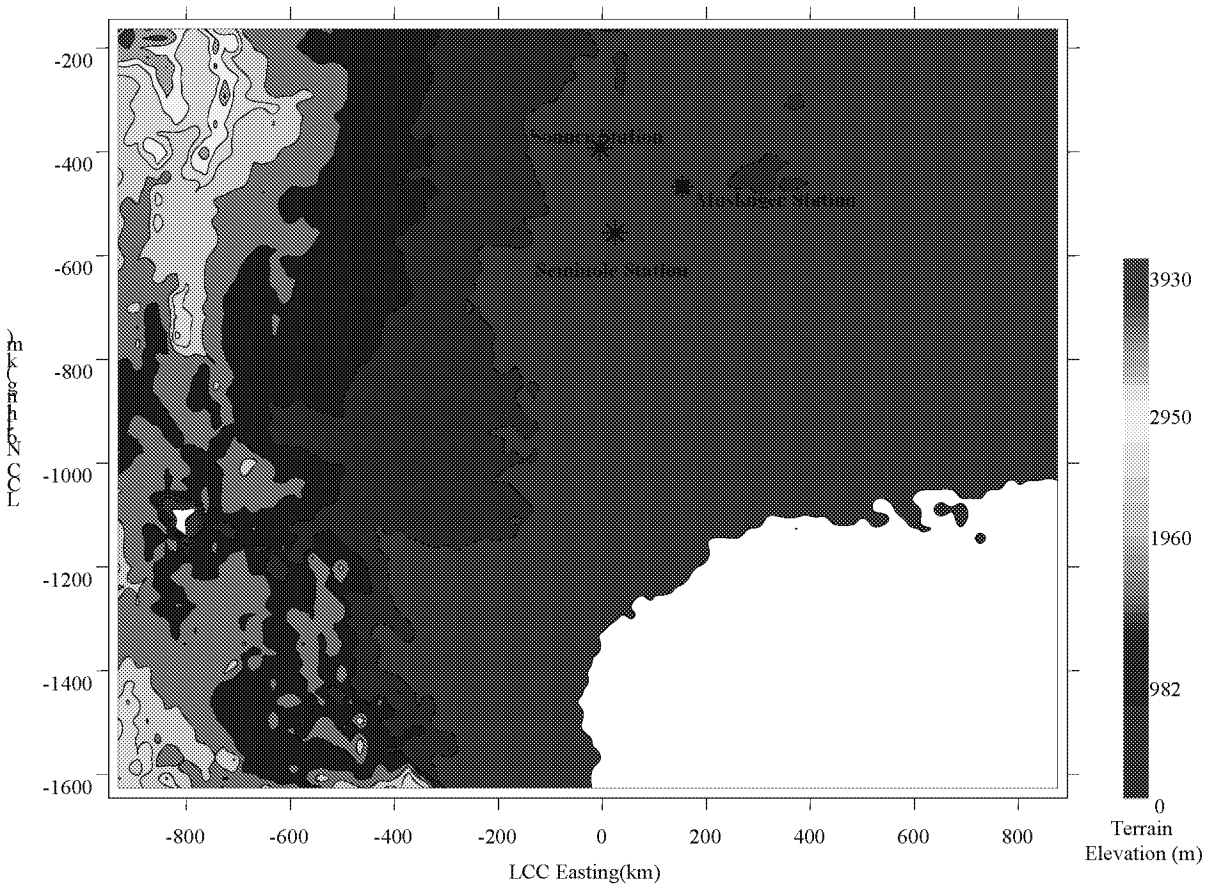
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

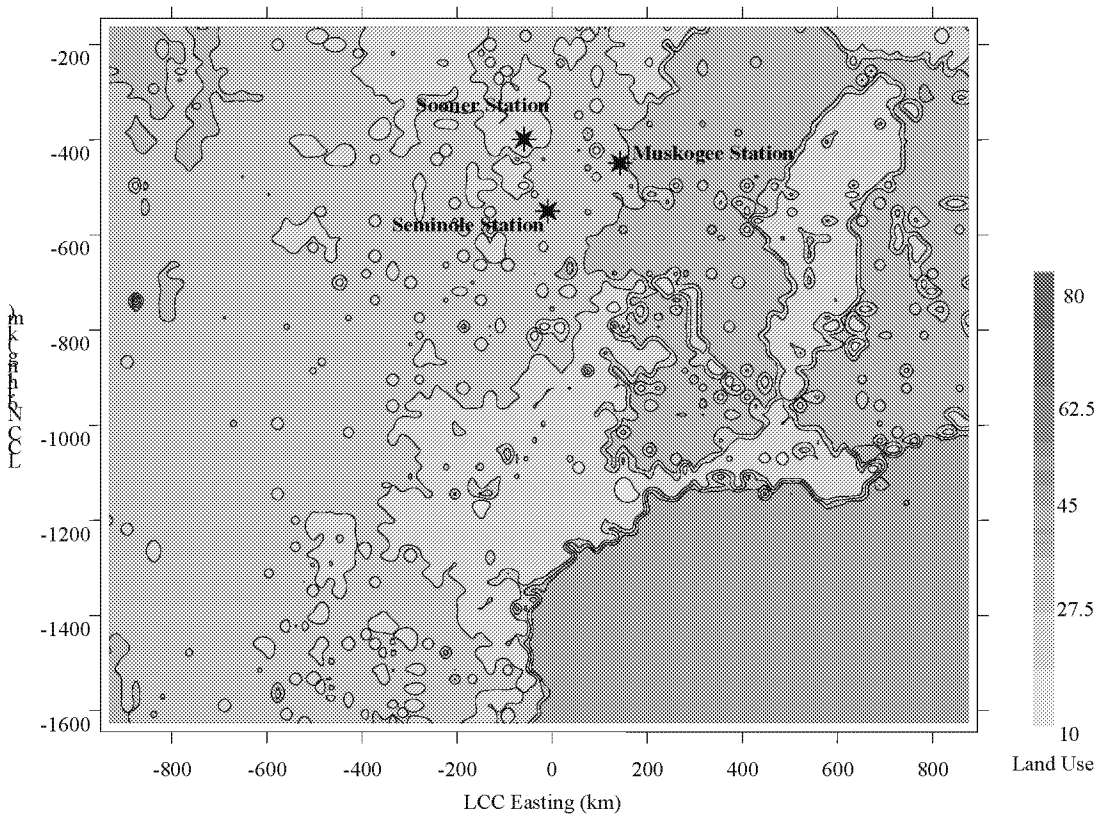
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

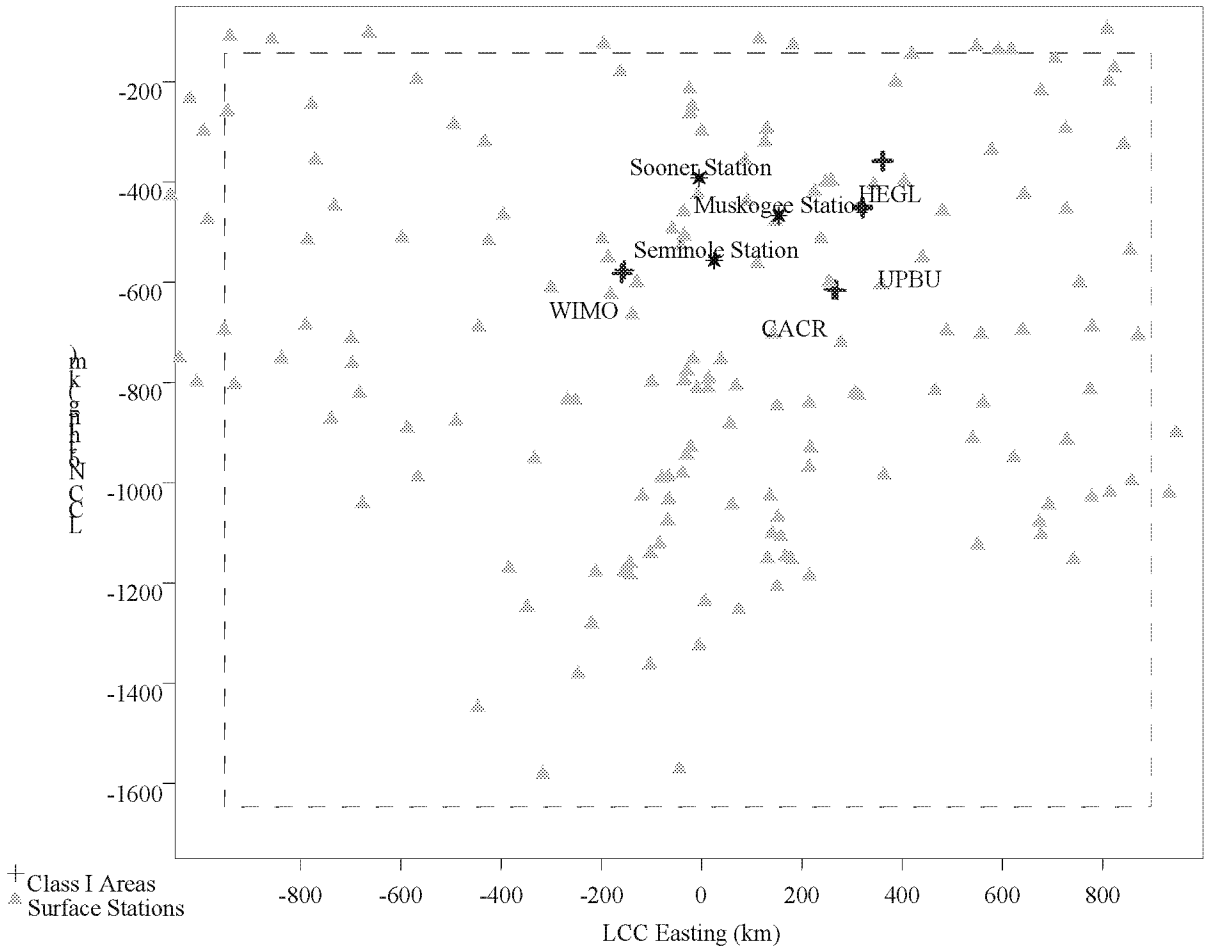
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

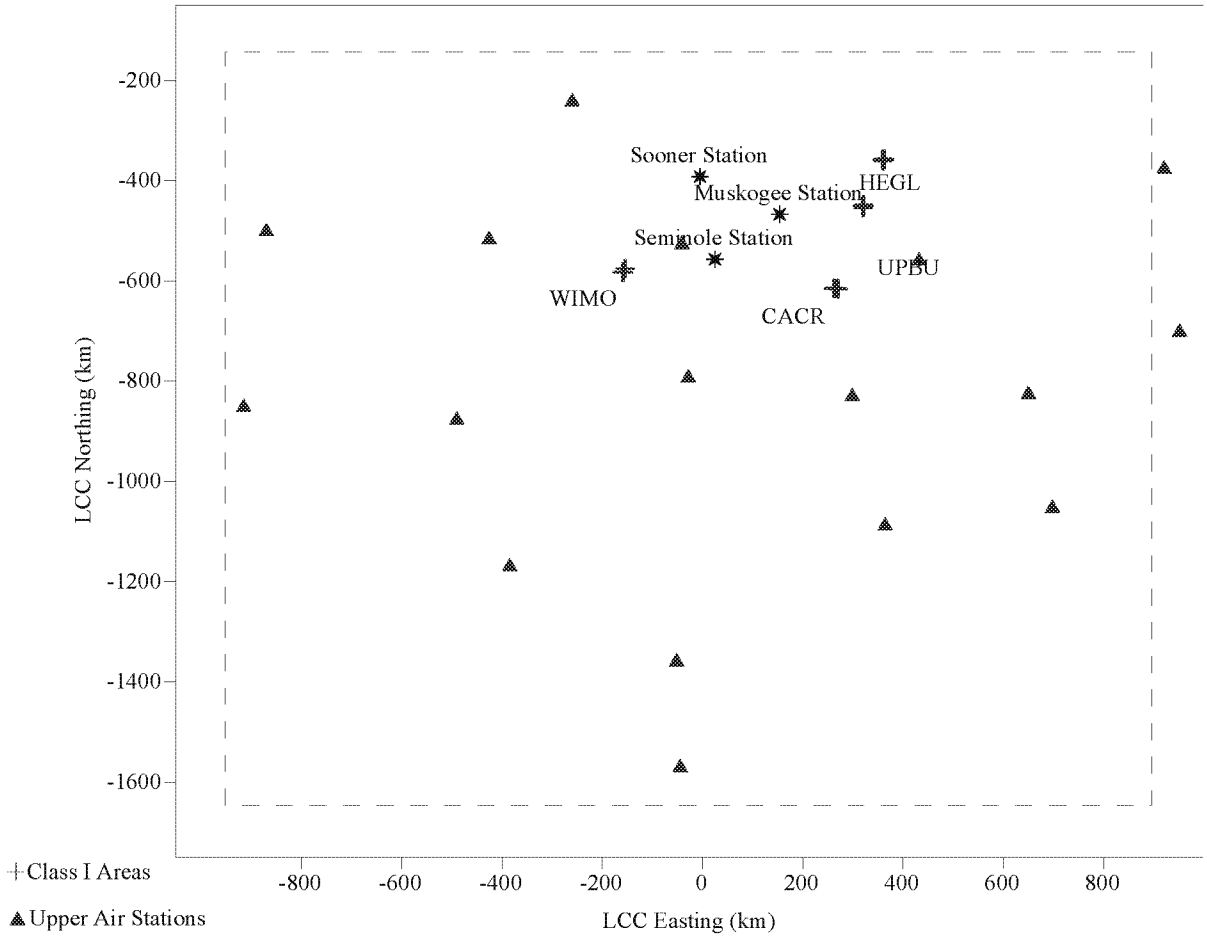
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

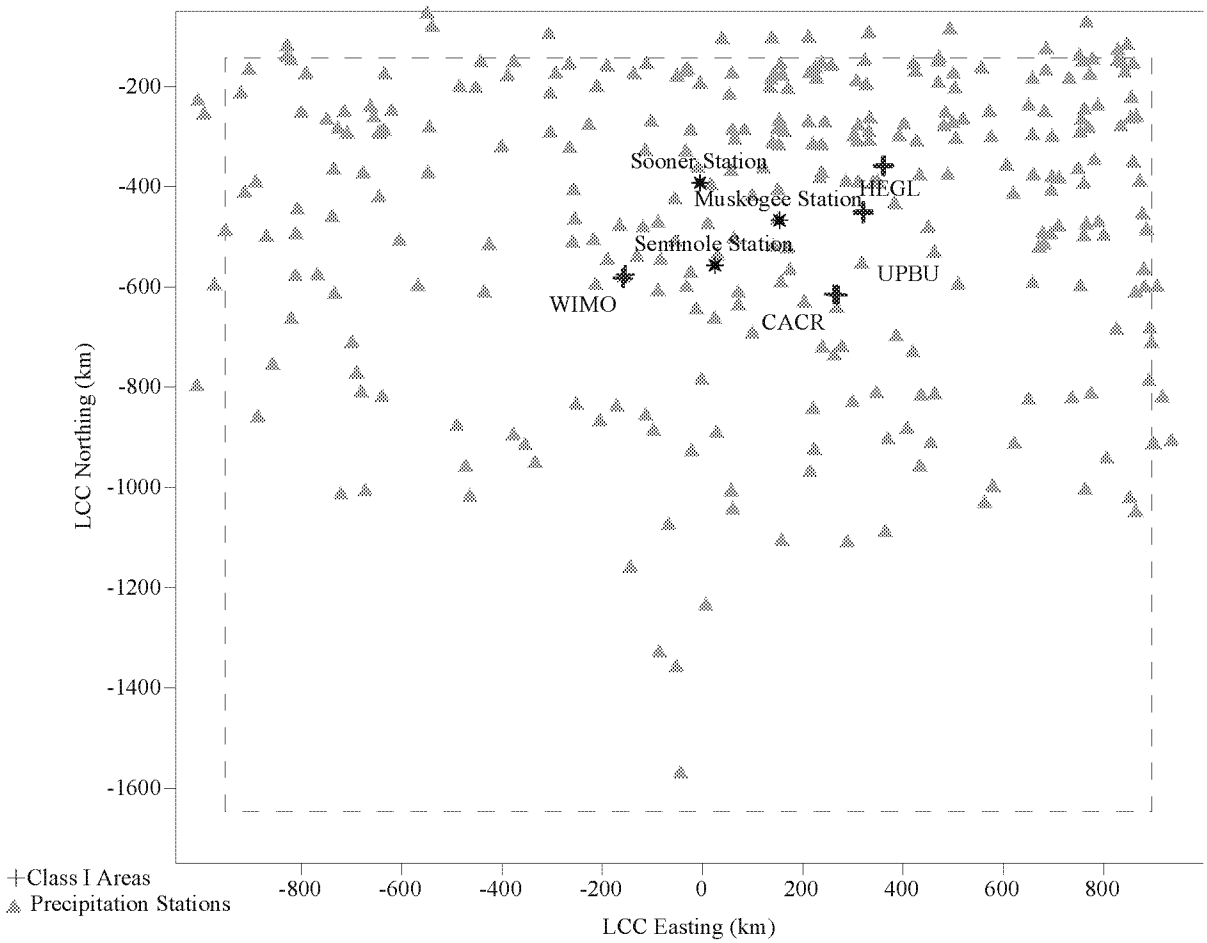
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

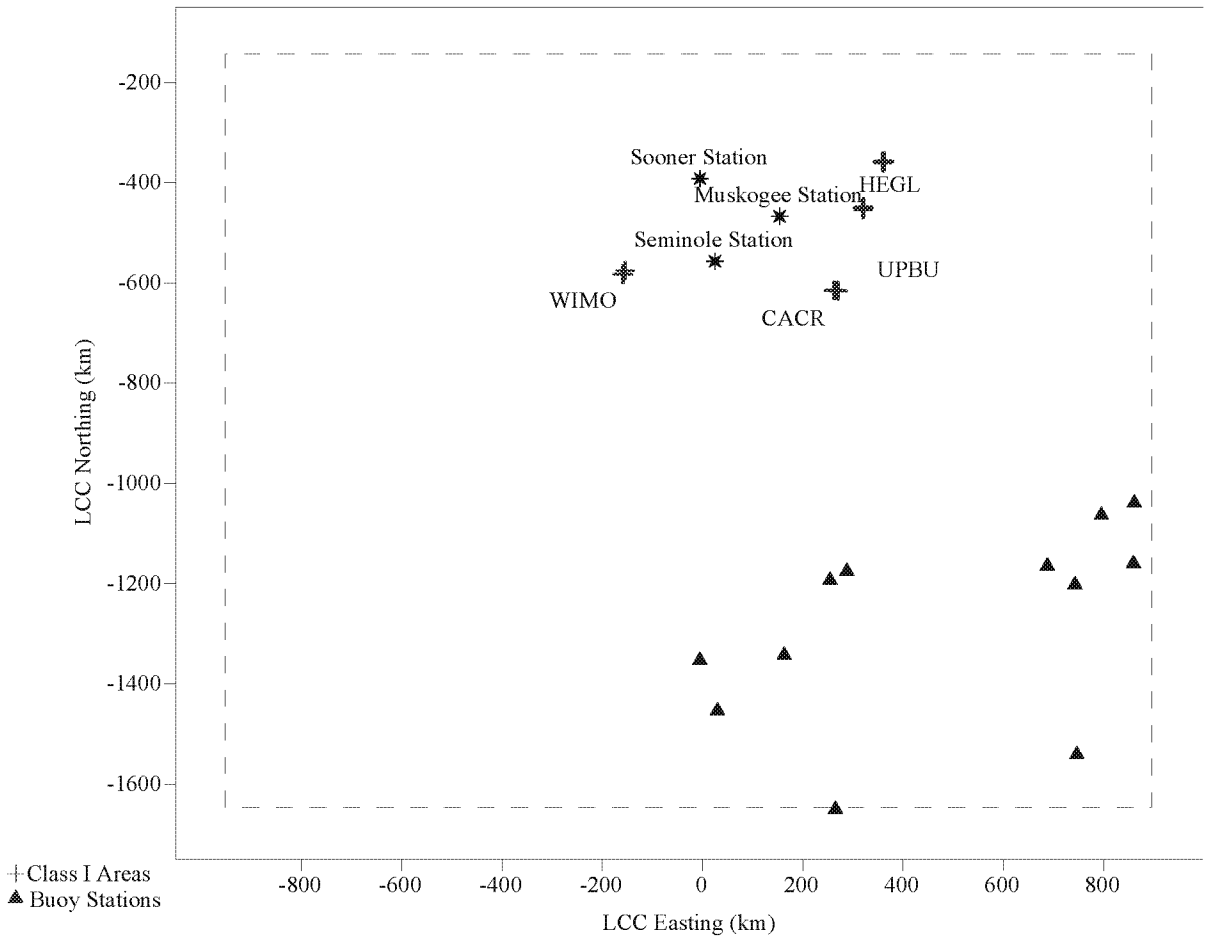
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

Date	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1/1/2001	0.014	0.202	4.787	46,087
1/2/2001	0.015	0.2243	5.535	48,831
1/3/2001	0.016	0.2324	6.465	54,856
1/4/2001	0.015	0.2472	6.835	51,150
1/5/2001	0.015	0.2295	5.827	48,783
1/6/2001	0.014	0.2258	5.828	48,253
1/7/2001	0.01	0.161	2.72	32,070
1/8/2001	0.013	0.1819	4.203	41,767
1/9/2001	0.014	0.207	5.35	45,700
1/10/2001	0.013	0.1957	4.699	43,529
1/11/2001	0.012	0.1942	4.459	41,573
1/12/2001	0.015	0.2103	6.049	50,330
1/13/2001	0.013	0.1802	4.325	42,266
1/14/2001	0.009	0.148	2.24	30,269
1/15/2001	0.01	0.1638	2.999	34,364
1/16/2001	0.012	0.1739	3.935	41,489
1/17/2001	0.013	0.1896	4.397	41,694
1/18/2001	0.015	0.2143	5.91	51,559
1/19/2001	0.012	0.1832	3.987	40,093
1/20/2001	0.01	0.1459	2.602	32,991
1/21/2001	0.012	0.1796	4.014	41,428
1/22/2001	0.013	0.1769	4.102	42,797
1/23/2001	0.013	0.185	4.93	42,499
1/24/2001	0.01	0.145	2.436	32,177
1/25/2001	0.011	0.1736	3.66	37,899
1/26/2001	0.013	0.1962	5.122	43,715
1/27/2001	0.009	0.1487	2.3	29,992
1/28/2001	0.008	0.1265	1.786	28,231
1/29/2001	0.012	0.1878	4.319	39,764
1/30/2001	0.01	0.1594	2.883	33,206
1/31/2001	0.01	0.1529	2.646	32,017
2/5/2001	0.006	0.086	1.466	20,118
2/6/2001	0.016	0.2086	6.165	53,744
2/7/2001	0.009	0.1866	3.213	31,084
2/18/2001	0.001	0.0188	0.038	3,928
2/19/2001	0.007	0.0982	1.368	24,718
2/20/2001	0.009	0.1274	1.913	29,778
2/21/2001	0.01	0.1512	2.869	34,778
2/22/2001	0.017	0.2335	7.695	56,681
2/23/2001	0.012	0.1743	3.807	39,905
2/24/2001	0.009	0.1102	1.623	29,044

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

2/25/2001	0.009	0.13	1.917	29,477
2/26/2001	0.009	0.1329	2.099	30,616
2/27/2001	0.003	0.1306	0.7	10,554
3/4/2001	0.001	0.0184	0.034	3,433
3/5/2001	0.002	0.0515	0.267	7,045
3/6/2001	0.014	0.221	6.083	48,166
3/7/2001	0.015	0.1927	5.478	48,645
3/8/2001	0.012	0.1555	3.269	38,946
3/9/2001	0.015	0.1743	4.568	50,545
3/10/2001	0.011	0.1549	2.964	35,761
3/11/2001	0.01	0.1379	2.435	33,295
3/12/2001	0.012	0.158	3.691	39,661
3/13/2001	0.012	0.1647	3.496	39,647
3/14/2001	0.009	0.1211	1.73	28,569
3/15/2001	0.01	0.141	2.735	33,742
3/16/2001	0.009	0.1279	1.961	30,403
3/17/2001	0.011	0.1602	3.19	36,852
3/18/2001	0.009	0.119	1.786	29,585
3/19/2001	0.014	0.207	5.529	47,177
3/20/2001	0.018	0.2443	8.471	59,677
3/21/2001	0.012	0.1685	3.87	39,580
3/22/2001	0.01	0.142	2.625	33,865
3/23/2001	0.012	0.1767	4.124	40,557
3/24/2001	0.012	0.1817	4.169	40,503
3/25/2001	0.011	0.1617	3.538	37,819
3/26/2001	0.021	0.2919	11.813	68,929
3/27/2001	0.018	0.2611	8.918	60,896
3/28/2001	0.02	0.2639	10.097	67,036
3/29/2001	0.014	0.1788	4.609	45,838
3/30/2001	0.016	0.2006	5.744	52,185
3/31/2001	0.011	0.159	3.131	37,184
4/1/2001	0.013	0.1752	4.115	42,033
4/2/2001	0.02	0.2338	8.676	66,851
4/3/2001	0.02	0.2369	8.8	66,241
4/4/2001	0.017	0.2038	6.068	55,481
4/5/2001	0.018	0.2004	6.511	60,051
4/6/2001	0.016	0.1907	5.821	52,912
4/7/2001	0.018	0.2262	7.664	59,423
4/8/2001	0.018	0.2364	8.721	58,721
4/9/2001	0.023	0.2954	12.863	76,082
4/10/2001	0.019	0.2176	7.726	64,086
4/11/2001	0.018	0.2098	6.773	58,358
4/12/2001	0.016	0.2128	6.479	54,940
4/13/2001	0.013	0.1945	4.508	42,639

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

4/14/2001	0.013	0.1562	3.497	42,801
4/15/2001	0.012	0.1644	3.577	40,030
4/16/2001	0.018	0.251	9.291	61,371
4/17/2001	0.014	0.167	4.133	45,200
4/18/2001	0.016	0.2087	6.585	52,319
4/19/2001	0.016	0.1903	5.171	51,766
4/20/2001	0.015	0.1854	4.984	49,224
4/21/2001	0.018	0.217	7.923	60,062
4/22/2001	0.014	0.1674	4.429	45,026
4/23/2001	0.022	0.3043	13.43	74,361
4/24/2001	0.016	0.2062	5.866	52,154
4/25/2001	0.011	0.1527	3.108	37,695
4/26/2001	0.017	0.2286	7.555	56,092
4/27/2001	0.016	0.2169	7.077	51,677
4/28/2001	0.015	0.1953	5.461	48,962
4/29/2001	0.014	0.1772	4.859	47,124
4/30/2001	0.017	0.2	6.797	56,452
5/1/2001	0.023	0.3154	14.69	78,193
5/2/2001	0.022	0.2717	11.62	71,844
5/3/2001	0.018	0.2036	7.091	61,269
5/4/2001	0.016	0.2144	7.245	54,351
5/6/2001	0.002	0.0339	0.123	5,083
5/7/2001	0.015	0.1868	5.25	50,120
5/8/2001	0.011	0.1553	3.234	37,663
5/9/2001	0.017	0.2099	7.313	57,056
5/10/2001	0.021	0.2753	11.622	69,100
5/11/2001	0.015	0.2005	5.819	51,008
5/12/2001	0.014	0.1828	4.776	45,391
5/13/2001	0.012	0.189	4.196	39,970
5/14/2001	0.015	0.1792	5.128	50,519
5/15/2001	0.02	0.2335	9.346	65,047
5/16/2001	0.019	0.2378	9.333	63,118
5/17/2001	0.02	0.2367	8.716	66,585
5/18/2001	0.016	0.184	5.893	52,147
5/19/2001	0.014	0.167	4.463	45,811
5/20/2001	0.013	0.1558	3.867	44,248
5/21/2001	0.011	0.1592	3.108	37,242
5/22/2001	0.008	0.153	2.12	27,721
5/23/2001	0.012	0.1763	3.876	39,538
5/24/2001	0.01	0.1579	3.086	34,319
5/25/2001	0.009	0.1198	1.699	28,368
5/26/2001	0.013	0.1813	4.857	43,433
5/27/2001	0.013	0.1806	4.355	42,547
5/28/2001	0.011	0.1718	3.231	35,115

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

5/29/2001	0.013	0.1931	5.097	43,171
5/30/2001	0.012	0.1745	3.803	40,685
5/31/2001	0.01	0.1417	2.62	33,567
6/1/2001	0.012	0.1624	3.551	39,572
6/2/2001	0.015	0.1946	5.796	49,384
6/3/2001	0.013	0.1658	4.242	44,794
6/4/2001	0.015	0.1862	5.395	50,776
6/5/2001	0.014	0.1903	5.198	46,681
6/6/2001	0.01	0.1415	2.706	34,818
6/7/2001	0.01	0.147	2.676	34,163
6/8/2001	0.013	0.1805	4.463	44,347
6/9/2001	0.01	0.1477	2.744	33,898
6/10/2001	0.012	0.1572	3.357	38,638
6/11/2001	0.017	0.2095	7.511	57,735
6/12/2001	0.019	0.2257	8.151	62,453
6/13/2001	0.019	0.2262	8.396	63,287
6/14/2001	0.019	0.218	7.851	62,402
6/15/2001	0.017	0.2161	7.572	57,158
6/16/2001	0.017	0.2303	7.86	57,767
6/17/2001	0.015	0.1928	5.518	50,985
6/18/2001	0.011	0.154	3.944	37,549
6/19/2001	0.003	0.0882	0.39	8,841
7/4/2001	0	0.012	0.002	340
7/5/2001	0.007	0.0781	1.602	24,168
7/6/2001	0.017	0.2128	7.052	56,775
7/7/2001	0.018	0.2179	7.562	60,597
7/8/2001	0.012	0.1569	3.968	39,226
7/9/2001	0.006	0.0961	1.025	21,338
7/10/2001	0.012	0.1546	4.264	41,608
7/11/2001	0.019	0.2223	8.412	63,578
7/12/2001	0.013	0.1621	4.021	43,458
7/13/2001	0.011	0.157	3.255	37,270
7/14/2001	0.013	0.1955	4.735	42,380
7/15/2001	0.013	0.1699	4.156	41,999
7/16/2001	0.019	0.2452	9.083	61,972
7/17/2001	0.019	0.2417	9.109	64,826
7/18/2001	0.016	0.2237	8.871	53,151
7/19/2001	0.007	0.1258	2.653	23,336
7/20/2001	0.019	0.249	9.25	64,264
7/21/2001	0.02	0.2328	8.491	65,463
7/22/2001	0.02	0.2443	9.321	68,224
7/23/2001	0.02	0.224	8.157	65,909
7/24/2001	0.02	0.2445	9.159	67,299
7/25/2001	0.019	0.2355	8.694	64,989

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

7/26/2001	0.013	0.1794	4.211	43,236
7/27/2001	0.013	0.1774	4.508	44,375
7/28/2001	0.019	0.2528	10.205	63,064
7/29/2001	0.019	0.2475	9.877	63,148
7/30/2001	0.022	0.2758	12.376	71,671
7/31/2001	0.022	0.2781	12.547	72,866
8/1/2001	0.019	0.2373	9.073	62,425
8/2/2001	0.021	0.2795	12.222	69,430
8/4/2001	0.016	0.1885	7.963	54,373
8/5/2001	0.021	0.2535	11.118	69,392
8/6/2001	0.025	0.2972	15.248	84,978
8/7/2001	0.025	0.2612	12.576	82,822
8/8/2001	0.025	0.3036	14.997	82,983
8/9/2001	0.025	0.3064	14.974	82,680
8/10/2001	0.019	0.2215	8.202	63,423
8/12/2001	0.013	0.1633	5.452	44,824
8/13/2001	0.006	0.1483	1.688	19,487
8/14/2001	0.002	0.0623	0.246	5,337
8/15/2001	0.008	0.1385	2.604	25,423
8/16/2001	0.018	0.2429	8.743	60,910
8/17/2001	0.018	0.2434	9.046	60,599
8/18/2001	0.015	0.1771	4.996	50,262
8/19/2001	0.014	0.1915	5.261	48,081
8/20/2001	0.018	0.2217	8.411	61,514
8/21/2001	0.021	0.2575	11.024	69,191
8/22/2001	0.017	0.2267	7.102	55,132
8/23/2001	0.016	0.1806	5.129	51,909
8/24/2001	0.022	0.2213	8.506	72,974
8/25/2001	0.022	0.2256	8.811	72,126
8/26/2001	0.02	0.2177	7.642	65,753
8/27/2001	0.02	0.2303	7.848	66,030
8/28/2001	0.021	0.2293	8.581	70,504
8/29/2001	0.021	0.2264	8.509	71,148
8/30/2001	0.022	0.2056	7.903	72,119
8/31/2001	0.015	0.1776	4.423	48,572
9/4/2001	0.017	0.1992	8.364	57,635
9/5/2001	0.02	0.2337	9.682	65,332
9/6/2001	0.024	0.2887	13.929	80,508
9/7/2001	0.026	0.3046	15.043	87,673
9/8/2001	0.019	0.2353	8.989	64,371
9/9/2001	0.012	0.1626	3.702	40,954
9/10/2001	0.019	0.2765	11.064	64,465
9/11/2001	0.015	0.2078	5.686	49,648
9/12/2001	0.02	0.2698	11.86	67,987

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

9/13/2001	0.023	0.287	13.566	75,247
9/14/2001	0.015	0.2122	6.49	50,987
9/15/2001	0.012	0.1745	4.057	41,586
9/16/2001	0.01	0.1532	2.834	34,143
9/17/2001	0.018	0.2053	7.027	59,845
9/18/2001	0.017	0.1845	5.837	55,340
9/19/2001	0.02	0.29	12.096	67,446
9/20/2001	0.014	0.1873	5.165	48,024
9/21/2001	0.015	0.1985	5.829	50,294
9/22/2001	0.017	0.2183	7.653	56,805
9/23/2001	0.009	0.1337	2.095	30,464
9/24/2001	0.011	0.153	3.113	36,686
9/25/2001	0.009	0.1394	2.293	31,182
9/26/2001	0.009	0.1375	2.009	29,212
9/27/2001	0.013	0.1991	4.898	43,804
9/28/2001	0.011	0.1601	3.348	38,249
9/29/2001	0.009	0.1273	1.879	29,507
9/30/2001	0.009	0.1299	1.915	29,494
10/1/2001	0.016	0.2279	7.078	54,478
10/2/2001	0.02	0.2719	10.453	67,704
10/3/2001	0.021	0.2808	11.517	70,491
10/4/2001	0.018	0.217	7.058	59,238
10/5/2001	0.017	0.2193	6.911	58,101
10/6/2001	0.011	0.1701	3.541	37,099
10/7/2001	0.012	0.173	4.088	40,906
10/8/2001	0.018	0.2333	7.922	60,878
10/9/2001	0.021	0.2618	10.653	71,124
10/10/2001	0.025	0.3041	14.046	84,843
10/11/2001	0.022	0.2695	10.787	72,705
10/12/2001	0.014	0.1858	4.721	46,018
10/13/2001	0.009	0.1202	1.806	30,005
10/14/2001	0.009	0.1397	2.083	29,826
10/15/2001	0.014	0.1868	4.97	46,963
10/16/2001	0.015	0.1948	5.346	50,101
10/17/2001	0.014	0.1865	5.001	46,094
10/18/2001	0.015	0.2042	5.707	49,980
10/19/2001	0.016	0.1879	5.568	54,454
10/20/2001	0.011	0.1695	3.665	38,306
10/21/2001	0.014	0.2021	5.378	46,550
10/22/2001	0.017	0.2118	7.204	57,917
10/23/2001	0.019	0.2224	8.303	64,766
10/24/2001	0.02	0.2506	9.924	68,044
10/25/2001	0.014	0.1916	4.787	46,344
10/26/2001	0.012	0.1569	3.256	39,305

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

10/27/2001	0.014	0.1796	4.434	45,299
10/28/2001	0.012	0.1632	3.641	40,671
10/29/2001	0.019	0.2607	9.652	64,118
10/30/2001	0.012	0.1614	3.716	41,285
10/31/2001	0.007	0.1413	1.716	22,574
11/2/2001	0.001	0.005	0.006	2,211
11/3/2001	0.012	0.1404	3.282	38,466
11/4/2001	0.009	0.1343	2.105	30,533
11/5/2001	0.017	0.2186	6.839	55,453
11/6/2001	0.019	0.2791	9.677	62,493
11/7/2001	0.022	0.3063	13.163	74,177
11/8/2001	0.016	0.226	6.573	53,905
11/9/2001	0.017	0.2095	6.302	56,263
11/10/2001	0.011	0.1513	2.83	35,031
11/11/2001	0.009	0.1295	1.881	29,044
11/12/2001	0.023	0.3233	14.175	76,017
11/13/2001	0.018	0.2403	8.093	59,969
11/14/2001	0.022	0.32	13.545	73,986
11/15/2001	0.019	0.2603	9.307	64,252
11/16/2001	0.02	0.2591	9.545	66,804
11/17/2001	0.015	0.2233	6.084	49,215
11/18/2001	0.01	0.1308	2.387	33,118
11/19/2001	0.015	0.1822	4.938	50,936
11/20/2001	0.014	0.181	4.702	46,801
11/21/2001	0.013	0.1629	3.929	42,621
11/28/2001	0.002	0.0235	0.15	7,641
11/29/2001	0.014	0.1843	4.9	47,614
11/30/2001	0.013	0.154	3.552	42,054
12/1/2001	0.013	0.1705	3.903	41,932
12/2/2001	0.011	0.1418	2.96	36,214
12/3/2001	0.012	0.1432	3.148	40,199
12/4/2001	0.009	0.1379	2.27	31,592
12/24/2001	0.002	0.0137	0.043	6,050
12/25/2001	0.01	0.1203	2.38	34,423
12/26/2001	0.013	0.1618	4.148	43,510
12/27/2001	0.014	0.1483	3.732	45,410
12/28/2001	0.011	0.1311	2.488	35,588
12/29/2001	0.011	0.1445	3.136	37,497
12/30/2001	0.015	0.1716	4.954	48,976
12/31/2001	0.012	0.1348	2.943	39,026
1/1/2002	0.011	0.1289	2.741	37,107
1/2/2002	0.019	0.2159	7.77	62,305
1/3/2002	0.014	0.1767	4.509	47,734
1/4/2002	0.013	0.1619	3.518	42,761

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

1/5/2002	0.015	0.1869	4.642	49,164
1/6/2002	0.011	0.1285	2.462	35,085
1/7/2002	0.014	0.1835	4.424	46,324
1/8/2002	0.012	0.1583	3.56	41,383
1/9/2002	0.009	0.1222	1.888	28,489
2/9/2002	0.016	0.011	0.296	52,507
2/10/2002	0.02	0.0207	0.606	66,669
2/11/2002	0.011	0.1331	2.365	36,624
2/12/2002	0.011	0.1611	3.084	36,846
2/13/2002	0.01	0.1785	3.229	34,397
2/14/2002	0.013	0.2097	4.987	43,360
2/15/2002	0.014	0.2086	5.029	45,459
2/16/2002	0.012	0.2087	4.505	41,526
2/17/2002	0.01	0.1814	2.984	31,880
2/18/2002	0.011	0.1988	3.921	37,465
2/19/2002	0.014	0.1981	4.872	45,380
2/20/2002	0.014	0.2173	5.256	45,213
2/21/2002	0.017	0.2381	6.925	55,851
2/22/2002	0.014	0.2127	5.232	46,535
2/23/2002	0.014	0.2037	4.945	46,575
2/24/2002	0.01	0.1896	3.281	32,913
2/25/2002	0.009	0.1759	2.747	30,582
2/26/2002	0.012	0.1834	3.845	41,052
2/27/2002	0.013	0.1826	3.942	42,493
2/28/2002	0.01	0.1566	2.711	34,015
3/1/2002	0.006	0.2166	2.028	18,483
3/15/2002	0.002	0.0235	0.123	7,253
3/16/2002	0.015	0.2207	5.787	49,573
3/17/2002	0.013	0.2006	4.429	42,117
3/18/2002	0.015	0.2198	5.663	49,072
3/19/2002	0.013	0.2061	4.707	42,893
3/20/2002	0.014	0.2145	5.842	47,868
3/21/2002	0.018	0.2544	8.371	59,345
3/22/2002	0.018	0.2707	9.128	58,545
3/23/2002	0.011	0.192	3.909	37,607
3/24/2002	0.011	0.1744	3.501	37,051
3/25/2002	0.019	0.2433	8.382	62,097
3/26/2002	0.018	0.2377	7.865	60,967
3/27/2002	0.014	0.2157	5.6	47,319
3/31/2002	0.001	0.0128	0.016	2,498
4/1/2002	0.012	0.1843	4.136	40,687
4/2/2002	0.014	0.2243	5.561	46,508
4/3/2002	0.015	0.2472	6.462	49,758
4/4/2002	0.014	0.2277	6.031	48,076

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

4/5/2002	0.012	0.2001	4.283	40,215
4/6/2002	0.011	0.191	3.747	37,023
4/7/2002	0.011	0.1853	3.678	36,988
4/8/2002	0.009	0.1468	2.22	30,245
4/9/2002	0.01	0.172	2.907	32,815
4/10/2002	0.013	0.2167	4.962	43,831
4/11/2002	0.016	0.2274	6.512	54,319
4/12/2002	0.016	0.2247	6.09	51,709
4/13/2002	0.017	0.2069	6.17	55,381
4/14/2002	0.013	0.1926	4.747	44,077
4/15/2002	0.018	0.2423	7.569	59,682
4/16/2002	0.019	0.2365	7.739	63,103
4/17/2002	0.02	0.2336	8.481	67,506
4/18/2002	0.018	0.224	7.316	61,168
4/19/2002	0.02	0.2517	8.836	65,022
5/2/2002	0.001	0.0148	0.017	2,211
5/3/2002	0.007	0.0993	1.714	24,898
5/4/2002	0.012	0.1863	3.914	40,781
5/5/2002	0.011	0.1728	3.337	37,451
5/6/2002	0.018	0.2097	6.908	59,594
5/7/2002	0.019	0.2303	8.425	64,152
5/8/2002	0.023	0.2361	9.35	75,224
5/9/2002	0.016	0.2122	5.898	52,439
5/10/2002	0.013	0.1986	4.614	44,164
5/11/2002	0.014	0.1765	4.683	47,444
5/12/2002	0.017	0.191	5.519	55,482
5/13/2002	0.009	0.1702	2.581	30,206
5/14/2002	0.009	0.161	2.348	29,134
5/15/2002	0.011	0.173	3.44	37,392
5/16/2002	0.021	0.2479	9.731	69,029
5/17/2002	0.012	0.2209	5.043	41,299
5/18/2002	0.01	0.188	3.206	33,448
5/19/2002	0.009	0.1645	2.379	28,929
5/20/2002	0.004	0.1594	1.021	12,647
6/1/2002	0.002	0.0113	0.034	5,847
6/2/2002	0.019	0.2273	9.398	63,706
6/3/2002	0.024	0.2836	13.792	81,176
6/4/2002	0.022	0.2306	9.943	73,180
6/5/2002	0.018	0.2241	7.916	61,459
6/6/2002	0.015	0.1971	5.382	48,636
6/7/2002	0.013	0.1934	4.553	43,848
6/8/2002	0.015	0.186	4.854	49,505
6/9/2002	0.013	0.1597	3.658	44,556
6/10/2002	0.017	0.1751	5.207	55,339

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

6/11/2002	0.016	0.1805	5.309	53,865
6/12/2002	0.017	0.1882	5.673	55,975
6/13/2002	0.017	0.1988	6.108	56,375
6/14/2002	0.011	0.1794	3.37	36,087
6/15/2002	0.013	0.1893	4.432	44,130
6/16/2002	0.011	0.169	3.104	35,720
6/17/2002	0.014	0.2101	5.291	47,773
6/18/2002	0.014	0.2049	5.253	47,076
6/19/2002	0.016	0.1944	5.498	52,049
6/20/2002	0.016	0.1911	5.7	54,348
6/21/2002	0.016	0.1905	5.506	53,336
6/22/2002	0.016	0.1816	5.251	54,099
6/23/2002	0.018	0.2016	6.77	59,249
6/24/2002	0.022	0.2445	10.128	72,397
6/25/2002	0.022	0.2426	10.262	72,043
6/26/2002	0.018	0.1814	5.963	60,244
6/27/2002	0.015	0.1849	4.94	50,555
6/28/2002	0.015	0.1851	5.1	51,646
6/29/2002	0.021	0.2412	9.898	69,078
6/30/2002	0.021	0.2355	9.247	68,381
7/1/2002	0.019	0.2164	7.691	64,385
7/2/2002	0.018	0.197	6.338	59,640
7/3/2002	0.017	0.1985	6.01	55,029
7/4/2002	0.019	0.2203	7.709	62,456
7/5/2002	0.021	0.2533	10.409	70,091
7/6/2002	0.021	0.2369	9.529	69,859
7/7/2002	0.02	0.2567	10.354	68,153
7/8/2002	0.024	0.2977	13.867	78,883
7/9/2002	0.022	0.2421	10.008	73,374
7/10/2002	0.019	0.2155	7.915	64,969
7/11/2002	0.006	0.1143	1.23	18,875
7/12/2002	0.013	0.168	3.94	43,917
7/13/2002	0.013	0.1685	3.834	43,460
7/14/2002	0.013	0.1713	3.981	42,789
7/15/2002	0.018	0.2131	7.348	59,142
7/16/2002	0.016	0.1863	5.406	53,142
7/17/2002	0.015	0.1769	4.941	51,354
7/18/2002	0.013	0.1603	3.517	42,566
7/19/2002	0.015	0.1703	4.591	50,001
7/20/2002	0.019	0.2103	7.674	63,309
7/21/2002	0.02	0.211	8.165	66,038
7/22/2002	0.018	0.1994	6.706	59,449
7/23/2002	0.017	0.1995	6.439	56,379
7/24/2002	0.014	0.1683	4.345	47,462

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

7/25/2002	0.018	0.2057	7.026	59,366
7/26/2002	0.019	0.2195	7.913	61,670
7/27/2002	0.02	0.2344	9.085	65,785
7/28/2002	0.02	0.2329	9.219	66,319
7/29/2002	0.018	0.2211	7.091	60,135
7/30/2002	0.019	0.1987	7.016	62,413
7/31/2002	0.02	0.2116	8.065	67,140
8/1/2002	0.02	0.2348	9.19	67,723
8/2/2002	0.02	0.2204	8.544	65,919
8/3/2002	0.021	0.233	9.727	71,119
8/4/2002	0.022	0.2389	10.048	72,709
8/5/2002	0.023	0.2528	11.034	76,430
8/6/2002	0.022	0.2487	10.381	72,419
8/7/2002	0.02	0.2277	8.971	66,020
8/8/2002	0.016	0.1953	5.712	54,134
8/9/2002	0.02	0.2207	8.389	66,924
8/10/2002	0.019	0.2229	8.173	63,200
8/11/2002	0.019	0.2428	9.007	64,645
8/12/2002	0.019	0.2223	8.197	63,315
8/13/2002	0.015	0.177	4.992	51,591
8/14/2002	0.013	0.1615	3.639	44,028
8/15/2002	0.014	0.1525	3.574	45,965
8/16/2002	0.014	0.178	4.527	47,668
8/17/2002	0.02	0.2145	8.039	66,775
8/18/2002	0.021	0.2241	9.121	71,329
8/19/2002	0.022	0.2147	8.779	72,190
8/20/2002	0.019	0.2123	8	64,039
8/21/2002	0.021	0.2276	9.215	69,432
8/22/2002	0.021	0.2321	9.377	71,456
8/23/2002	0.023	0.235	9.958	75,098
8/24/2002	0.023	0.2532	10.574	78,007
8/25/2002	0.003	0.1184	0.839	9,352
8/26/2002	0.016	0.1796	6.672	54,640
8/27/2002	0.018	0.2074	7.099	59,167
8/28/2002	0.017	0.2014	7.045	57,669
8/29/2002	0.015	0.1921	5.529	51,098
8/30/2002	0.017	0.2171	7.671	57,804
8/31/2002	0.015	0.1841	5.165	51,198
9/1/2002	0.014	0.1783	4.742	48,187
9/2/2002	0.02	0.2379	9.75	67,051
9/3/2002	0.022	0.2633	11.663	74,026
9/4/2002	0.022	0.2336	10.178	73,496
9/5/2002	0.021	0.2239	9.081	69,350
9/6/2002	0.019	0.2164	8.132	63,607

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

9/7/2002	0	0.142	0.077	1,086
9/8/2002	0.002	0.0866	0.477	7,847
9/9/2002	0.02	0.2438	9.69	68,073
9/10/2002	0.022	0.2685	12.292	74,588
9/11/2002	0.02	0.2608	10.642	66,892
9/12/2002	0.017	0.227	7.805	55,975
9/13/2002	0.016	0.2185	6.919	54,441
9/14/2002	0.017	0.201	6.647	58,026
9/15/2002	0.015	0.1733	4.41	48,560
9/16/2002	0.015	0.1741	4.554	49,299
9/17/2002	0.014	0.1813	4.473	46,893
9/18/2002	0.019	0.2025	7.282	62,050
9/19/2002	0.015	0.1645	4.117	48,986
9/20/2002	0.016	0.1949	5.813	54,811
9/21/2002	0.017	0.2213	7.779	57,523
9/22/2002	0.015	0.1887	4.946	48,475
9/23/2002	0.017	0.2053	6.094	57,656
9/24/2002	0.009	0.1612	2.532	31,042
9/25/2002	0.009	0.1522	2.184	28,696
9/26/2002	0.009	0.1447	2.192	30,380
9/27/2002	0.016	0.1781	5.067	53,614
9/28/2002	0.02	0.2236	9.112	65,596
9/29/2002	0.018	0.2112	7.366	58,893
9/30/2002	0.024	0.2666	12.481	79,285
10/1/2002	0.02	0.22	8.269	65,225
10/2/2002	0.017	0.1763	5.171	55,756
10/3/2002	0.01	0.148	2.42	32,066
10/4/2002	0.024	0.2682	12.474	81,557
10/5/2002	0.02	0.2543	9.726	68,123
10/6/2002	0.021	0.2488	10.73	70,725
10/7/2002	0.017	0.2079	6.327	55,178
10/8/2002	0.009	0.1534	2.324	30,329
10/9/2002	0.011	0.1682	3.296	37,760
10/10/2002	0.011	0.1739	3.359	37,865
10/11/2002	0.013	0.1826	3.949	42,777
10/12/2002	0.016	0.1726	4.821	52,701
10/13/2002	0.012	0.1787	3.52	38,416
10/14/2002	0.014	0.1891	4.577	45,296
10/15/2002	0.011	0.1567	2.851	35,609
10/16/2002	0.012	0.1799	3.735	39,422
10/17/2002	0.009	0.1603	2.453	28,618
10/20/2002	0.002	0.0122	0.036	5,771
10/21/2002	0.018	0.2094	7.817	62,036
10/22/2002	0.02	0.2096	7.478	65,071

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

10/23/2002	0.013	0.1826	4.527	44,437
10/24/2002	0.015	0.1721	4.372	49,483
10/25/2002	0.014	0.1658	4.185	47,824
10/26/2002	0.011	0.1546	2.944	35,938
10/27/2002	0.013	0.1601	3.608	43,240
10/28/2002	0.02	0.2088	7.729	65,115
10/29/2002	0.016	0.194	5.532	54,367
10/30/2002	0.015	0.188	4.794	48,862
10/31/2002	0.011	0.1581	2.904	35,231
11/1/2002	0.011	0.1485	2.819	36,574
11/2/2002	0.01	0.145	2.383	31,903
11/3/2002	0.011	0.1482	2.848	35,811
11/4/2002	0.023	0.2648	12.133	78,254
11/5/2002	0.021	0.2342	9.378	68,889
11/6/2002	0.015	0.1738	4.608	49,173
11/7/2002	0.02	0.2313	8.749	65,161
11/8/2002	0.017	0.1781	5.178	56,524
11/9/2002	0.009	0.136	2.161	31,346
11/10/2002	0.01	0.1448	2.362	31,887
11/11/2002	0.013	0.1856	4.725	44,136
2/14/2003	0.001	0.015	0.013	1,699
2/16/2003	0.001	0.008	0.018	4,605
2/17/2003	0.017	0.007	0.196	55,932
2/18/2003	0.012	0.1238	2.05	41,073
2/19/2003	0.003	0.1366	0.708	9,395
3/28/2003	0.002	0.0242	0.107	7,599
3/29/2003	0.013	0.1843	4.455	44,910
3/30/2003	0.011	0.1648	3.195	37,684
3/31/2003	0.011	0.1599	3.049	37,123
4/1/2003	0.009	0.1645	2.533	30,638
4/2/2003	0.009	0.1578	2.455	30,591
4/3/2003	0.006	0.1202	1.32	19,515
4/4/2003	0.005	0.102	0.967	15,489
4/5/2003	0.009	0.1568	2.442	30,236
4/6/2003	0.009	0.1436	2.17	29,975
4/7/2003	0.011	0.15	3.071	37,476
4/8/2003	0.012	0.1548	3.05	38,738
4/9/2003	0.015	0.1841	5.177	50,011
4/10/2003	0.01	0.141	2.445	34,069
4/11/2003	0.009	0.1414	2.113	29,972
4/12/2003	0.009	0.1431	2.162	30,296
4/13/2003	0.008	0.1405	1.976	28,127
4/14/2003	0.01	0.1486	2.56	33,621
4/15/2003	0.007	0.1452	1.758	24,188

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

4/25/2003	0.003	0.0553	0.492	11,035
4/26/2003	0.01	0.1436	2.364	32,877
4/27/2003	0.01	0.1418	2.309	31,985
4/28/2003	0.008	0.1336	1.711	25,610
5/9/2003	0.004	0.0611	0.614	12,647
5/10/2003	0.017	0.2021	6.54	57,405
5/11/2003	0.01	0.1643	2.778	32,877
5/12/2003	0.01	0.17	3.027	34,463
5/13/2003	0.01	0.1454	2.497	33,067
5/14/2003	0.008	0.1238	1.727	27,904
5/15/2003	0.009	0.1203	1.765	28,349
5/16/2003	0.009	0.129	2.082	31,551
5/17/2003	0.008	0.1178	1.644	27,919
5/18/2003	0.01	0.1452	2.588	34,093
5/19/2003	0.016	0.1815	4.992	51,799
5/20/2003	0.004	0.1189	0.738	11,975
6/1/2003	0.002	0.0204	0.091	7,884
6/2/2003	0.01	0.125	2.122	33,776
6/3/2003	0.009	0.1308	1.946	29,693
6/4/2003	0.01	0.1464	2.454	32,222
6/5/2003	0.007	0.1192	1.338	21,933
6/6/2003	0.007	0.1182	1.317	21,747
6/7/2003	0.006	0.1135	1.1	19,380
6/8/2003	0.006	0.1165	1.136	19,497
6/9/2003	0.002	0.1092	0.387	6,865
6/30/2003	0.002	0.0148	0.051	6,666
7/1/2003	0.01	0.1128	1.846	32,090
7/2/2003	0.01	0.1271	2.185	32,181
7/3/2003	0.01	0.136	2.453	33,123
7/4/2003	0.006	0.0813	1.036	21,649
7/5/2003	0.007	0.1085	1.225	21,943
7/6/2003	0.009	0.1127	1.813	29,175
7/7/2003	0.012	0.138	3.41	40,692
7/8/2003	0.011	0.1252	2.581	36,435
7/9/2003	0.01	0.1078	2.01	34,360
7/10/2003	0.007	0.1007	1.228	23,077
7/11/2003	0.01	0.1343	2.455	33,518
7/12/2003	0.01	0.1307	2.379	32,929
7/13/2003	0.009	0.1247	1.94	29,003
7/14/2003	0.013	0.1405	3.51	43,006
7/15/2003	0.015	0.185	4.892	50,793
7/16/2003	0.014	0.1793	5.3	47,457
7/17/2003	0.013	0.1686	3.913	42,782
7/18/2003	0.013	0.165	4.07	43,826

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

7/19/2003	0.008	0.1224	1.76	25,804
7/20/2003	0.01	0.1375	2.73	34,139
7/21/2003	0.013	0.1501	3.85	44,737
7/22/2003	0.006	0.103	1.121	21,104
7/23/2003	0.006	0.1008	1.011	19,929
7/24/2003	0.006	0.1075	1.072	19,935
7/25/2003	0.009	0.1438	2.495	31,066
7/26/2003	0.011	0.1486	3.135	35,801
7/27/2003	0.013	0.173	5.431	44,064
7/28/2003	0.017	0.2069	6.998	58,049
7/29/2003	0.011	0.1515	3.021	36,394
7/30/2003	0.007	0.1108	1.516	24,235
7/31/2003	0.009	0.1397	2.345	31,381
8/1/2003	0.01	0.1266	2.392	34,091
8/2/2003	0.006	0.092	0.892	19,398
8/3/2003	0.006	0.0904	0.875	19,360
8/4/2003	0.009	0.1192	2.303	30,760
8/5/2003	0.01	0.1227	2.572	34,455
8/6/2003	0.008	0.1203	1.763	26,244
8/7/2003	0.008	0.1309	1.829	25,444
8/8/2003	0.008	0.1298	2.097	27,401
8/9/2003	0.007	0.1191	1.409	22,463
8/10/2003	0.006	0.1079	1.061	19,660
8/11/2003	0.006	0.1075	1.061	19,738
8/12/2003	0.006	0.1095	1.08	19,725
8/13/2003	0.006	0.1065	1.048	19,690
8/14/2003	0.008	0.1326	2.107	28,151
8/15/2003	0.01	0.1322	2.58	33,848
8/16/2003	0.013	0.1526	3.956	42,216
8/17/2003	0.013	0.1577	4.289	43,090
8/18/2003	0.014	0.1655	4.59	47,382
8/19/2003	0.014	0.1708	5.163	46,902
8/20/2003	0.015	0.1618	5.32	49,507
8/21/2003	0.014	0.1881	5.674	48,299
8/22/2003	0.012	0.166	3.744	41,589
8/23/2003	0.01	0.1376	2.684	32,518
8/24/2003	0.01	0.1334	2.577	33,755
8/25/2003	0.014	0.1732	4.318	45,380
8/26/2003	0.013	0.1547	3.525	42,822
8/27/2003	0.01	0.1459	2.67	33,331
8/28/2003	0.01	0.1498	2.62	32,451
8/29/2003	0.013	0.1693	3.995	43,374
8/30/2003	0.012	0.1627	3.506	40,500
8/31/2003	0.006	0.0985	0.948	19,262

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

9/1/2003	0.01	0.1333	2.529	33,302
9/2/2003	0.008	0.1248	1.888	27,757
9/3/2003	0.008	0.1173	1.595	25,074
9/4/2003	0.008	0.1225	1.797	26,458
9/5/2003	0.006	0.105	1.099	20,221
9/6/2003	0.006	0.1046	1.019	19,416
9/7/2003	0.006	0.1108	1.228	21,382
9/8/2003	0.009	0.1403	2.307	29,597
9/9/2003	0.01	0.1442	2.718	32,493
9/10/2003	0.009	0.1393	2.427	30,284
9/11/2003	0.008	0.126	1.829	26,313
9/12/2003	0.006	0.1015	0.992	19,325
9/13/2003	0.009	0.1308	2.093	28,954
9/14/2003	0.007	0.1298	1.696	24,158
9/15/2003	0.007	0.129	1.71	24,800
9/16/2003	0.007	0.1279	1.697	24,474
9/17/2003	0.007	0.1288	1.716	24,273
9/18/2003	0.007	0.1259	1.509	22,736
9/19/2003	0.006	0.1163	1.157	19,547
9/20/2003	0.008	0.1318	1.753	25,392
9/21/2003	0.007	0.1188	1.465	23,212
9/22/2003	0.01	0.1355	2.401	34,680
9/23/2003	0.009	0.1447	2.381	31,309
9/24/2003	0.01	0.1484	2.635	34,458
9/25/2003	0.01	0.1461	2.608	32,192
9/26/2003	0.011	0.1719	3.773	37,670
9/27/2003	0.012	0.1762	4.114	40,712
9/28/2003	0.006	0.1263	1.249	19,773
9/29/2003	0.006	0.1286	1.388	21,146
9/30/2003	0.007	0.1355	1.688	23,273
10/1/2003	0.006	0.1358	1.542	21,627
10/5/2003	0.002	0.0366	0.114	5,808
10/6/2003	0.01	0.1548	2.763	32,216
10/7/2003	0.013	0.1837	4.234	44,450
10/8/2003	0.009	0.156	2.64	30,400
10/18/2003	0	0.0105	0.007	1,196
10/19/2003	0.009	0.1316	2.367	28,415
10/20/2003	0.015	0.1955	5.096	51,193
10/21/2003	0.017	0.2215	7.467	57,794
10/22/2003	0.028	0.3428	16.509	93,036
10/23/2003	0.025	0.2927	12.561	82,673
10/24/2003	0.024	0.2452	9.877	79,990
10/25/2003	0.03	0.3455	17.916	98,845
10/26/2003	0.023	0.2924	12.033	78,223

Entergy Arkansas, Inc.
Lake Catherine - Unit 4
CEMS Data from CAMD

10/27/2003	0.012	0.1688	3.629	38,963
10/28/2003	0.012	0.1751	3.723	38,838
10/29/2003	0.01	0.1726	3.271	34,783
10/30/2003	0.008	0.1362	1.893	25,485
10/31/2003	0.005	0.1143	1.042	17,440
11/9/2003	0.002	0.0359	0.172	7,344
11/10/2003	0.006	0.1283	1.306	20,363
11/11/2003	0.026	0.3002	15.338	85,158
11/12/2003	0.037	0.4825	29.477	122,153
11/13/2003	0.02	0.3162	14.539	67,701
11/14/2003	0.016	0.2494	9.144	53,543
11/15/2003	0.023	0.309	14.475	76,658
11/16/2003	0.014	0.2057	7.065	47,591
11/17/2003	0.011	0.1664	3.785	37,220
11/18/2003	0.004	0.1328	0.842	11,838
12/11/2003	0.001	0.024	0.051	3,992
12/12/2003	0.008	0.1213	1.843	25,998
12/13/2003	0.009	0.137	2.2	28,738
12/14/2003	0.006	0.118	1.209	20,460
12/15/2003	0.009	0.1466	2.348	30,084
Max (tpd) -->	**0.037**		**29.477**	
Max (lb/hr) -->	**3.1**		**2456.4**	

Note: Dates with no operation/emissions not shown

APPENDIX D

SARGENT & LUNDY NO_X CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

EPA-HQ-2018-002296

LEGAL NOTICE

This report ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Gill Elrod Ragon Owen & Sherman, P.A. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

ED_002110_00032765-00089

EPA-HQ-2018-002296

White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

CONTRIBUTORS

Prepared by:

Kristen C Bell — 5/16/2013
Kristen Bell — Date
Environmental Associate

Joy Rooney — 5/16/2013
Joy Rooney — Date
Environmental Associate

Reviewed by:

Steve Katzberger — 5/16/2013
Steve Katzberger — Date
Environmental Lead

Approved by:

S. C. McHone — 5/16/2013
Sean McHone — Date
Project Manager

ED_002110_00032765-00090

EPA-HQ-2018-002296

ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering. The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: Sean C. McHone Date: 5/16/2013

Seal:

STATE OF ARKANSAS
LICENSED PROFESSIONAL ENGINEER
No. 15308
SEAN C. McHONE

S. C. McHone
5/16/2013

Issue:	Date:	Certified By:	Pages Certified:

ED_002110_00032765-00091

1. INTRODUCTION 1
1.1. OBJECTIVE 1
1.2. UNIT DESCRIPTIONS 1
1.2.1. White Bluff - Units 1 & 2 1
1.2.2. White Bluff Auxiliary Boiler 1
1.2.3. Lake Catherine - Unit 4 1
1.3. ESTIMATE METHODOLOGY 2
1.3.1. Capital Cost Estimates 2
1.3.2. Operating and Maintenance Cost Estimates 3
1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES 3
2. WHITE BLUFF - UNITS 1 & 2 4
2.1. FUEL SWITCHING OPTIONS 4
2.1.1. Natural Gas 4
2.1.2. Propane 4
2.2. COMBUSTION CONTROLS 4
2.2.1. Low NOx Burners and Over-Fire Air 4
2.2.2. Flue Gas Recirculation (FGR) 5
2.2.3. Neural Network 5
2.3. POST COMBUSTION CONTROLS 6
2.3.1. Selective Non-Catalytic Reduction 6
2.3.2. Selective Catalytic Reduction 7
2.4. CAPITAL COSTS 8
2.5. OPERATING AND MAINTENANCE COSTS 9
3. WHITE BLUFF AUXILIARY BOILER 11
3.1. FUEL SWITCHING 11
3.2. COMBUSTION CONTROLS 11
3.2.1. Low NOx Burners + Over-Fire Air 11
3.2.2. Flue Gas Recirculation 11
3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation 11
3.2.4. Neural Network 12
3.3. POST COMBUSTION CONTROLS 12
3.3.1. Selective Non-Catalytic Reduction 12
3.3.2. Selective Catalytic Reduction 12

EPA-HQ-2018-002296

3.4. CAPITAL COST ESTIMATES 13
3.5. OPERATING AND MAINTENANCE COST ESTIMATES 13
4. LAKE CATHERINE - UNIT 4 15
4.1. FUEL SWITCHING 15
4.2. COMBUSTION CONTROLS 15
4.2.1. Burners-Out-Of-Service 15
4.2.2. Low NOx Burners + Over-Fire Air 16
4.2.3. Flue Gas Recirculation 16
4.2.4. Water Injection 16
4.2.5. Neural Network 17
4.3. POST COMBUSTION CONTROLS 17
4.3.1. Selective Non-Catalytic Reduction 17
4.3.2. Selective Catalytic Reduction 17
4.4. CAPITAL COST ESTIMATES 18
4.5. OPERATING AND MAINTENANCE COST ESTIMATES 19
APPENDIX A: CAPITAL COST ESTIMATE 2
1. BASIS OF ESTIMATES 2
2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS 2
APPENDIX B 3
1. ESTIMATED PROJECT SCHEDULES 3
APPENDIX C 4
1. OPERATING AND MAINTENANCE COST ESTIMATES 4
APPENDIX D 5
1. BOOS AT FULL UNIT LOAD 5

ED_002110_00032765-00093

EPA-HQ-2018-002296

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

ED_002110_00032765-00094

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The "design target" NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission

rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame

temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) into the furnace at high flue gas temperatures (approximately 1600 °F – 2000 °F). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 °F – 2000 °F. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous

EPA-HQ-2018-002296

long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

ED_002110_00032765-00101

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			**Unit 2**		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx

from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original "high" burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated "fuel rich", lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for

the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	Controlled NOx (lb/MMBtu)	Total Installed Capital Cost (2012$)
Baseline	0.4825[1]	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	Variable O&M[1,2] Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

Client: Entergy
Station: White Bluff/Lake Catherine
Project No.: 13027-001

Preparer: A Hays
Date: 09/04/2012 (Rev 0)

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station.
White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as "Variable Accounts". These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10's Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
  - 31813A @ 19% of construction cost
  - 31814A @ 8% of construction cost
  - 31815A @ 8% of construction cost
  - 31816A @ 16% of construction cost
  - 31817A @ 6% of construction cost
  - 31818A @ 6% of construction cost
  - 31819A @ 8% of construction cost
  - 31820A @ 12% of construction cost
  - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
  - 31813A @ 6% of construction cost
  - 31814A @ 3% of construction cost
  - 31815A @ 2% of construction cost
  - 31816A @ 6% of construction cost
  - 31817A @ 2% of construction cost

  - 31818A @ 2% of construction cost
  - 31819A @ 2% of construction cost
  - 31820A @ 0% of construction cost
  - 31832A @ 6% of construction cost
- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

ESTIMATE NO.: 31813A2
PROJECT NO.: 13027-001
ISSUE DATE:
PREP./REV.: ADH/
APPROVED:

ENTERGY - LAKE CATHERINE
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

ESTIMATE NO.: 31814A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - LAKE CATHERINE
SCR SYSTEM - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

ESTIMATE NO.: 31815A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - LAKE CATHERINE
SNCR SYSTEM - UNIT 4
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

ESTIMATE NO.: 31816A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

ESTIMATE NO.: 31819A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SNCR SYSTEM - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

ESTIMATE NO.: 31817A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SCR - UNIT 1
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

ESTIMATE NO.: 31832A
PROJECT NO.: 13027-001
ISSUE DATE: 8/31/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
LOW NOX BURNERS AND OVERFIRE AIR SYSTEMS - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

ESTIMATE NO.: 31840A
PROJECT NO.: 13027-001
ISSUE DATE: 9/7/2012
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SNCR SYSTEM - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

ESTIMATE NO.: 31818A
PROJECT NO.: 13027-001
ISSUE DATE:
PREP./REV.: ADH/
APPROVED: MNO

ENTERGY - WHITE BLUFF
SCR - UNIT 2
CONCEPTUAL ESTIMATE

Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

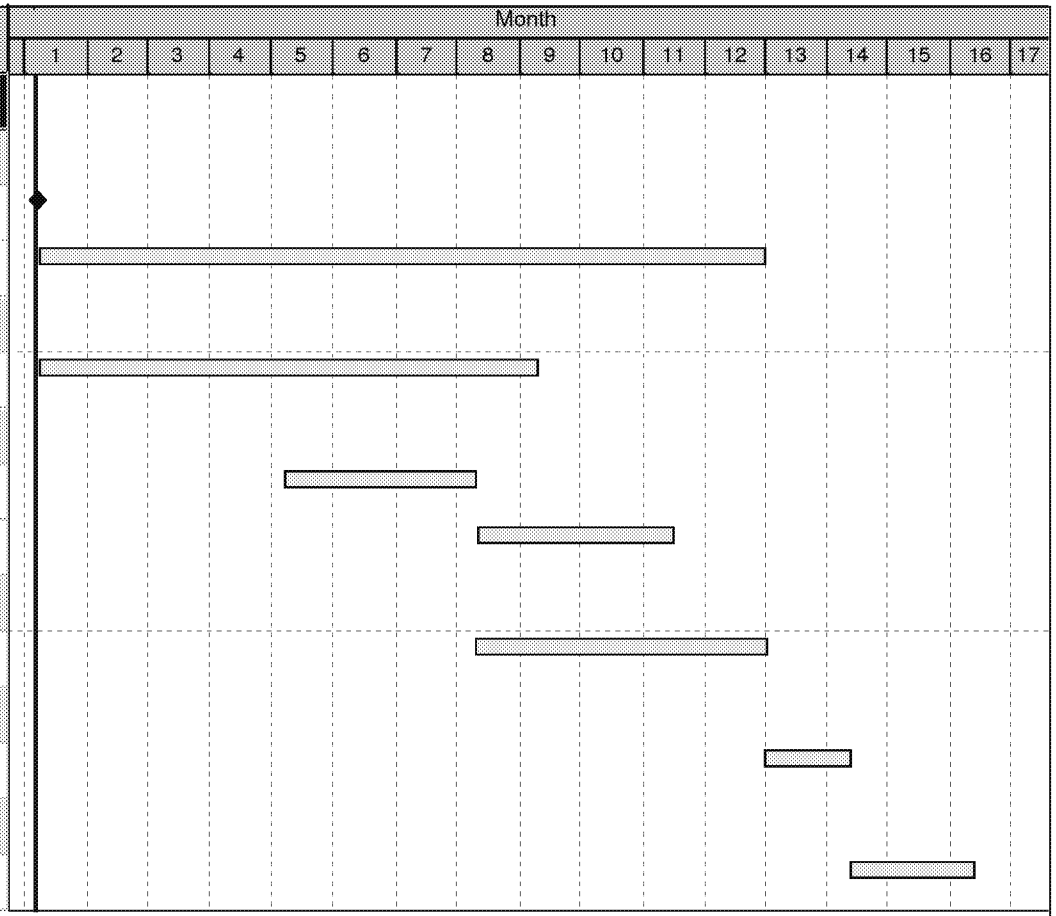
EPA-HQ-2018-002296

APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

ED_002110_00032765-00126

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		6m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		5m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

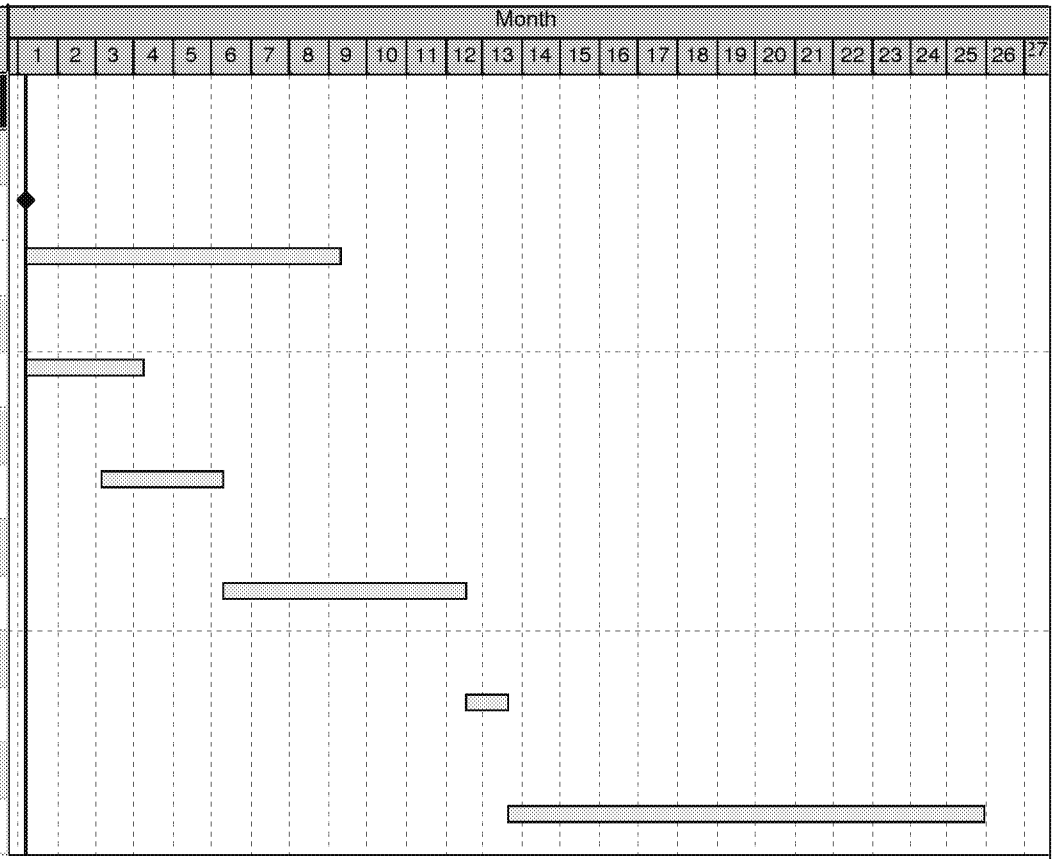


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for
Entergy Services, Inc. White Bluff and Lake Catherine
Aux Boiler Low NOx Burner/Over-Fire Air/Flue Gas Recirculation (LNB/OFA/FGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Neural Network		24m
Permitting		8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
Engineering		3m
A1020	Engineering	3m
Procurement of Major Equipment		3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		12m
A1060	Commissioning & Start-Up	12m

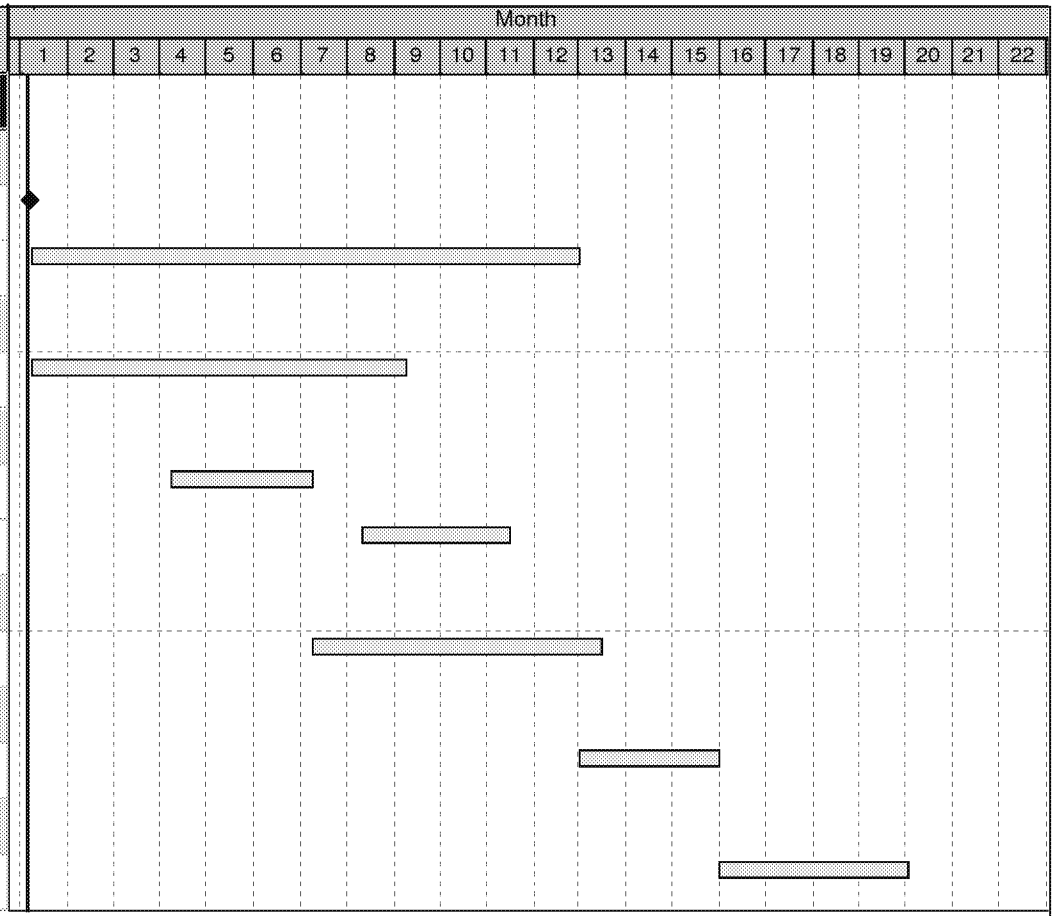


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Neural Network

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Low NOx Burners/Over ...		19m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
Installation		3m
A1050	Installation	3m
Commissioning & Start-Up		4m
A1060	Commissioning & Start-Up	4m

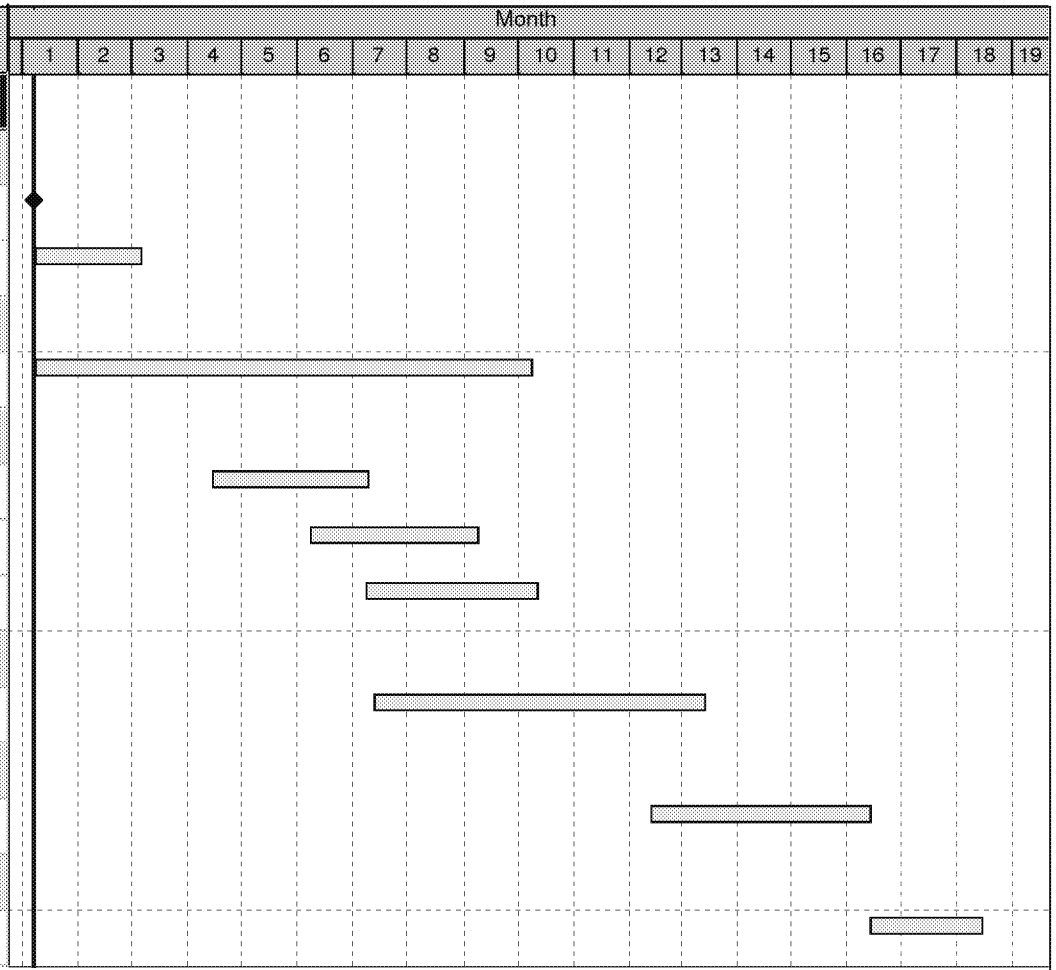


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Low NOx Burners/Over-Fire Air (LNB/OFA)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Induced Flue Gas Recir...		17m
Permitting		2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
Engineering		9m
A1020	BOP Engineering	9m
Procurement of Major Equipment		6m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
Installation		4m
A1050	Installation	4m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

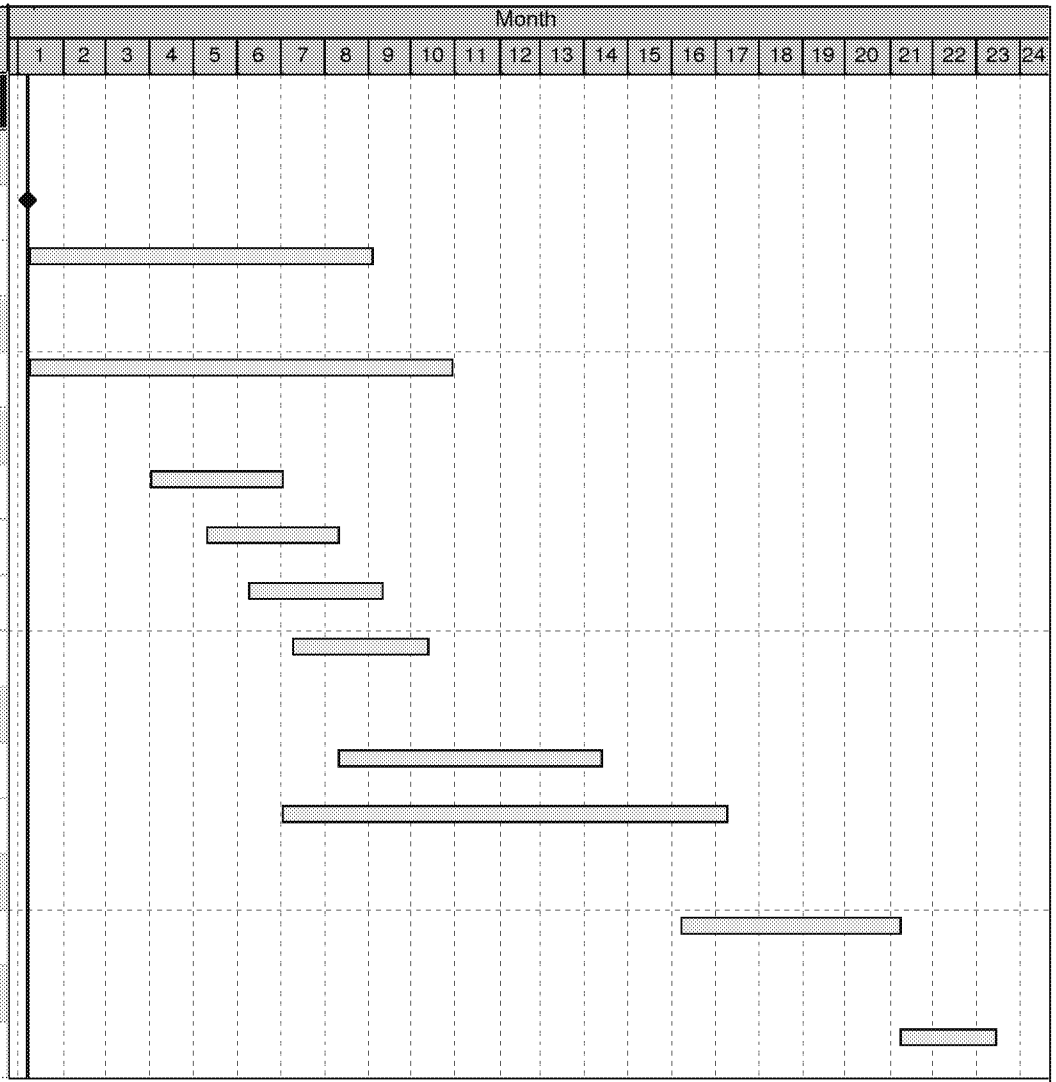


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Induced Flue Gas Recirculation (IFGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Flue Gas Recirculation ...	22m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	10m
A1020	BOP Engineering	10m
	Procurement of Major Equipment	6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
	Installation	5m
A1050	Installation	5m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m

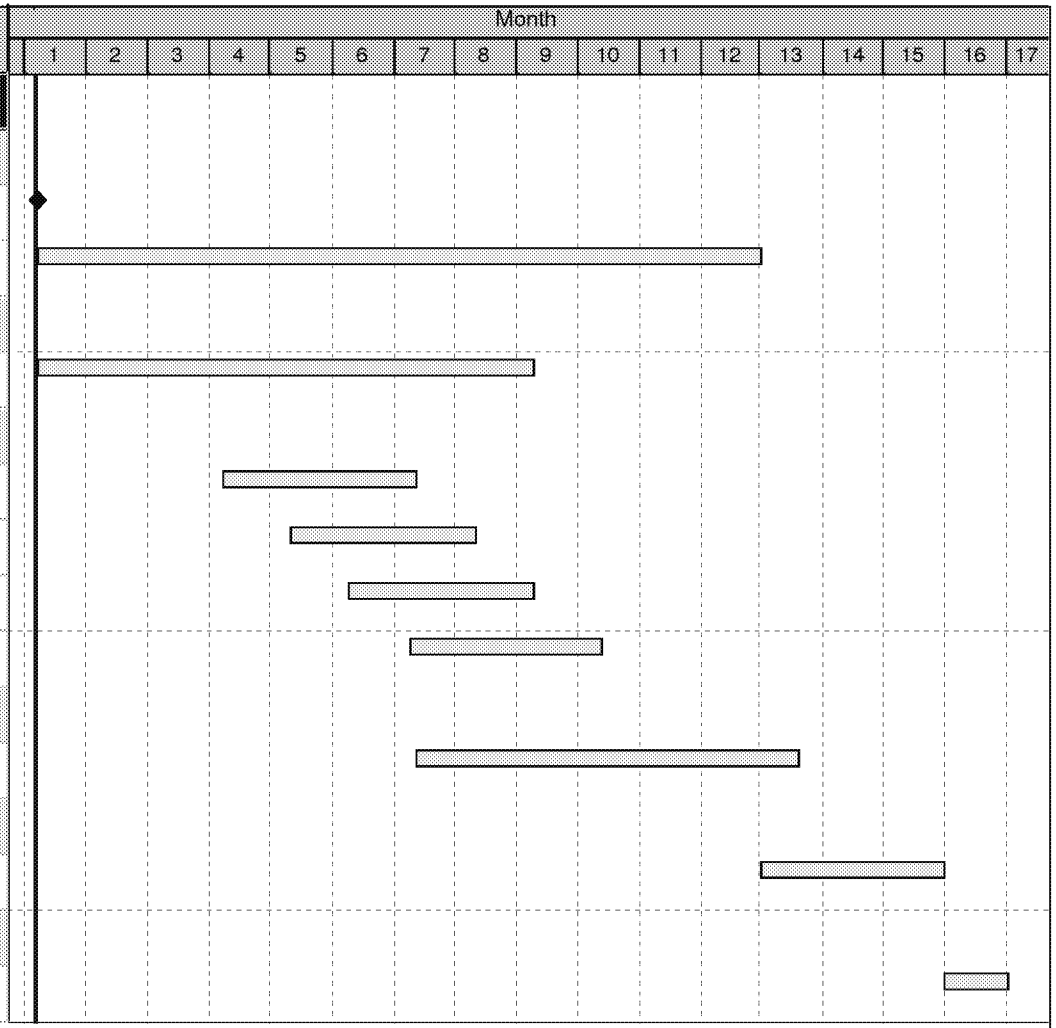


Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Flue Gas Recirculation (FGR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Selective Non-Catalytic ...		16m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	BOP Engineering	8m
Procurement of Major Equipment		6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
Installation		3m
A1050	Installation	3m
Commissioning & Start-Up		1m
A1060	Commissioning & Start-Up	1m

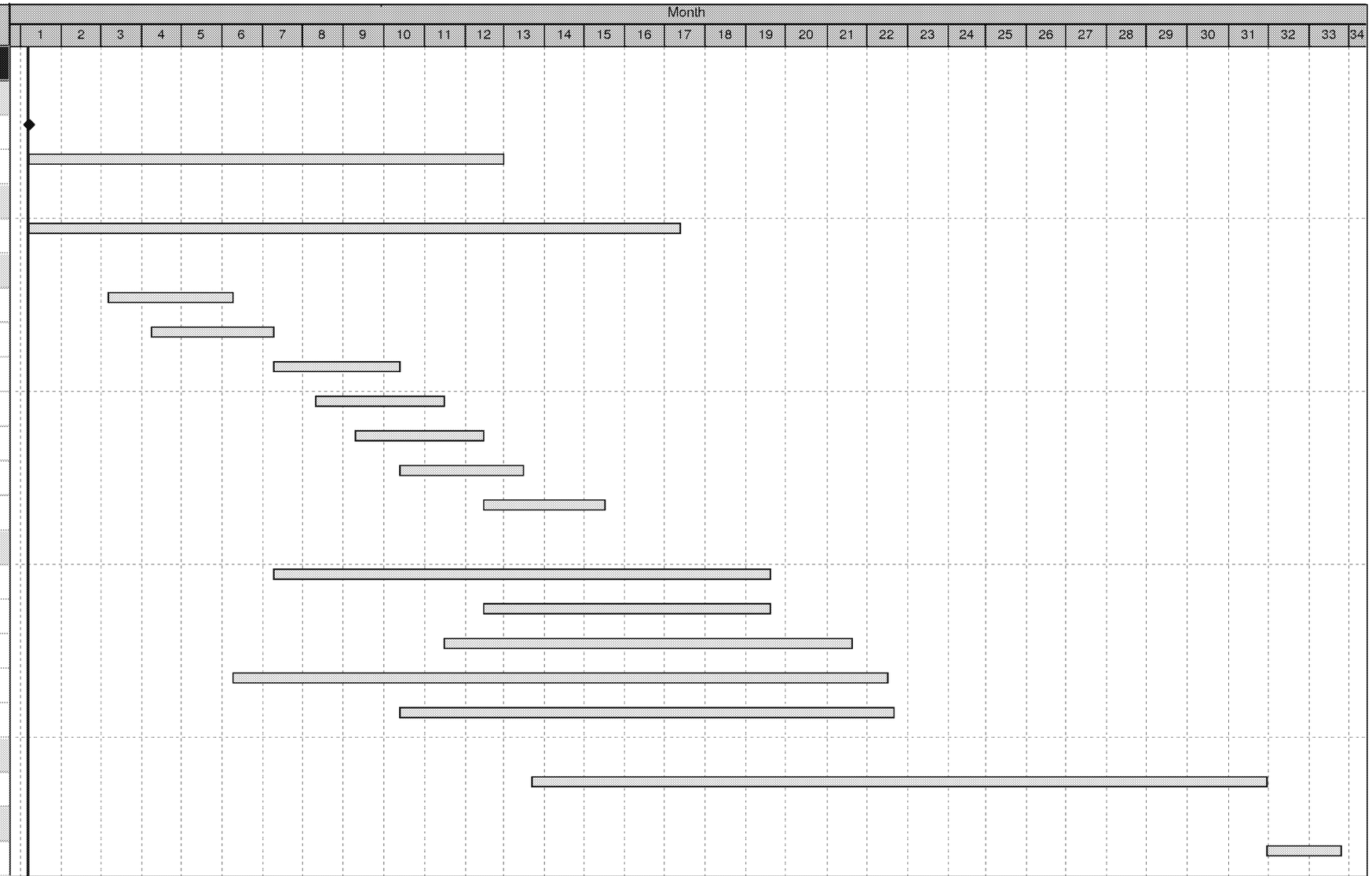


Run Date: 09-14-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Non-Catalytic Reduction (SNCR)

Sargent & Lundy

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Selective Catalytic Red...		32m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		16m
A1020	BOP Engineering	16m
Procurement of Major Equipment		12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
Installation		18m
A1050	Installation	18m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m



Run Date: 09-17-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Catalytic Reduction (SCR)

Sargent & Lundy

EPA-HQ-2018-002296

APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

ED_002110_00032765-00134

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit Name White Bluff 2

Unit Data		Reagent Costs	
Size (Gross kW)	844,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,604.3	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**31.833**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit name Lake Catherine Unit 4

Unit Data	
Size (Gross kW)	558,000
Average NOx Emission Rate (lb/MMBtu)	0.4825
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0
Avg. Heat Rate (Btu/kwh)	10,483.9
Aux. Power (kw)	-
Est. Capacity Factor (%)	10.00
Boiler Type	T/F
Boiler Eff. (%)	82
Estimated NOx, tons/day Max	3.387
Emission Limit, tons	-
NOx Sales/Buy rate, $/ton	2500.0
Fuel	Gas
Seasonal Days	153
Basis	0
Analysis - Enter "0" for Annual and 1 for Seasonal	
CF For Variable O&M	10.00

Reagent Costs	
Aq.Ammonia $/t	$700
An.Ammonia $/t	$400
Urea $/t	$350
N/F-T Urea $/t	$618
Gas Cost, $/MBtu	4.900
Water Cost, $/1000 gal (3)	2
Electricity, $/MWh	41.50

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost		
							Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

EPA-HQ-2018-002296

APPENDIX D

1. BOOS AT FULL UNIT LOAD

ED_002110_00032765-00138

To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

****
This e-mail and any of its attachments may contain ETEC Inc. proprietary information, which is privileged, confidential, or subject to copyright belonging to the ETEC Inc. This e-mail is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this e-mail, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this e-mail is strictly prohibited and may be unlawful. If you have received this e-mail in error, please notify the sender immediately and permanently delete the original and any copy of this e-mail and any printout. Thank You.

********** BOOS for NOx Control.pdf

Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction

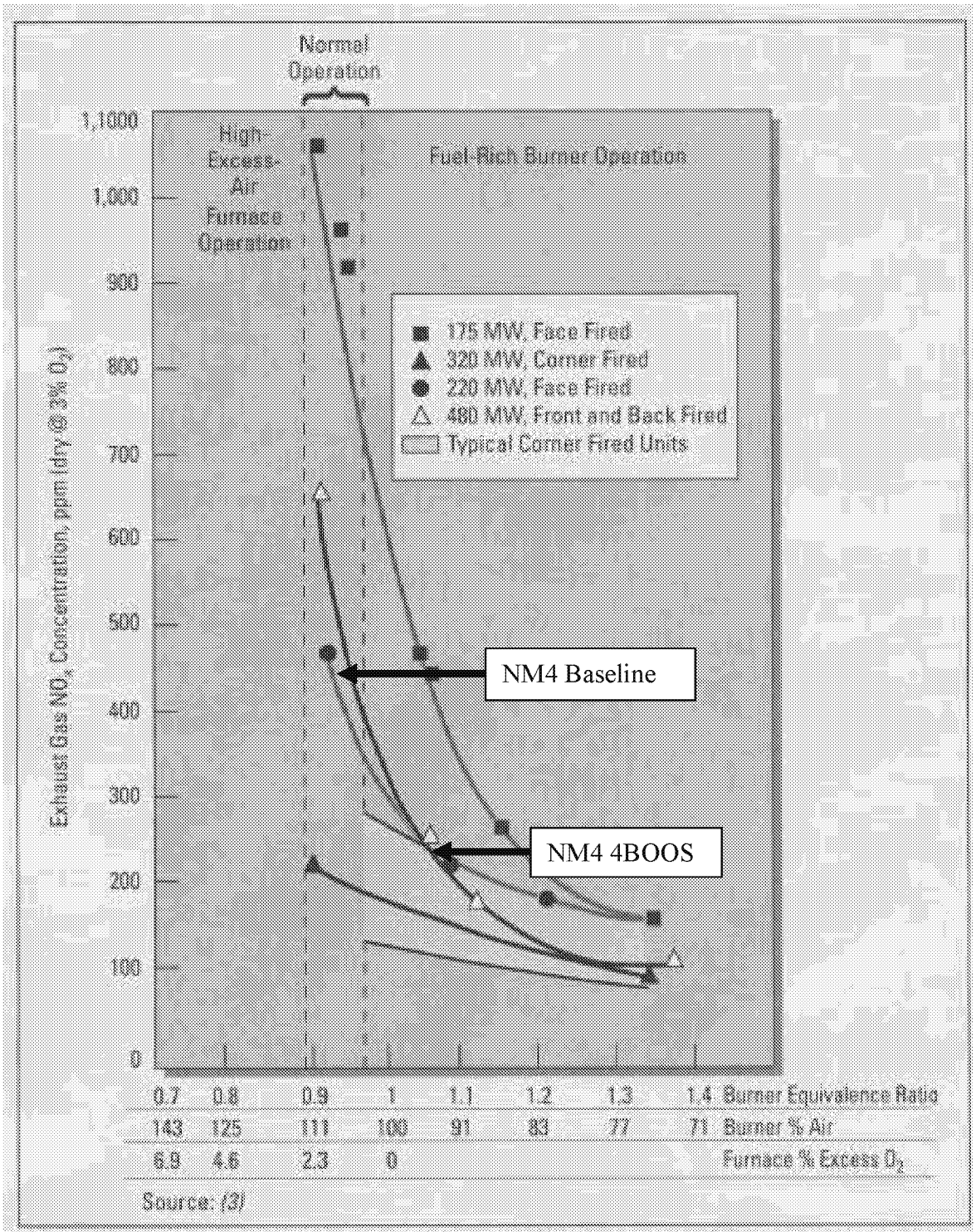


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

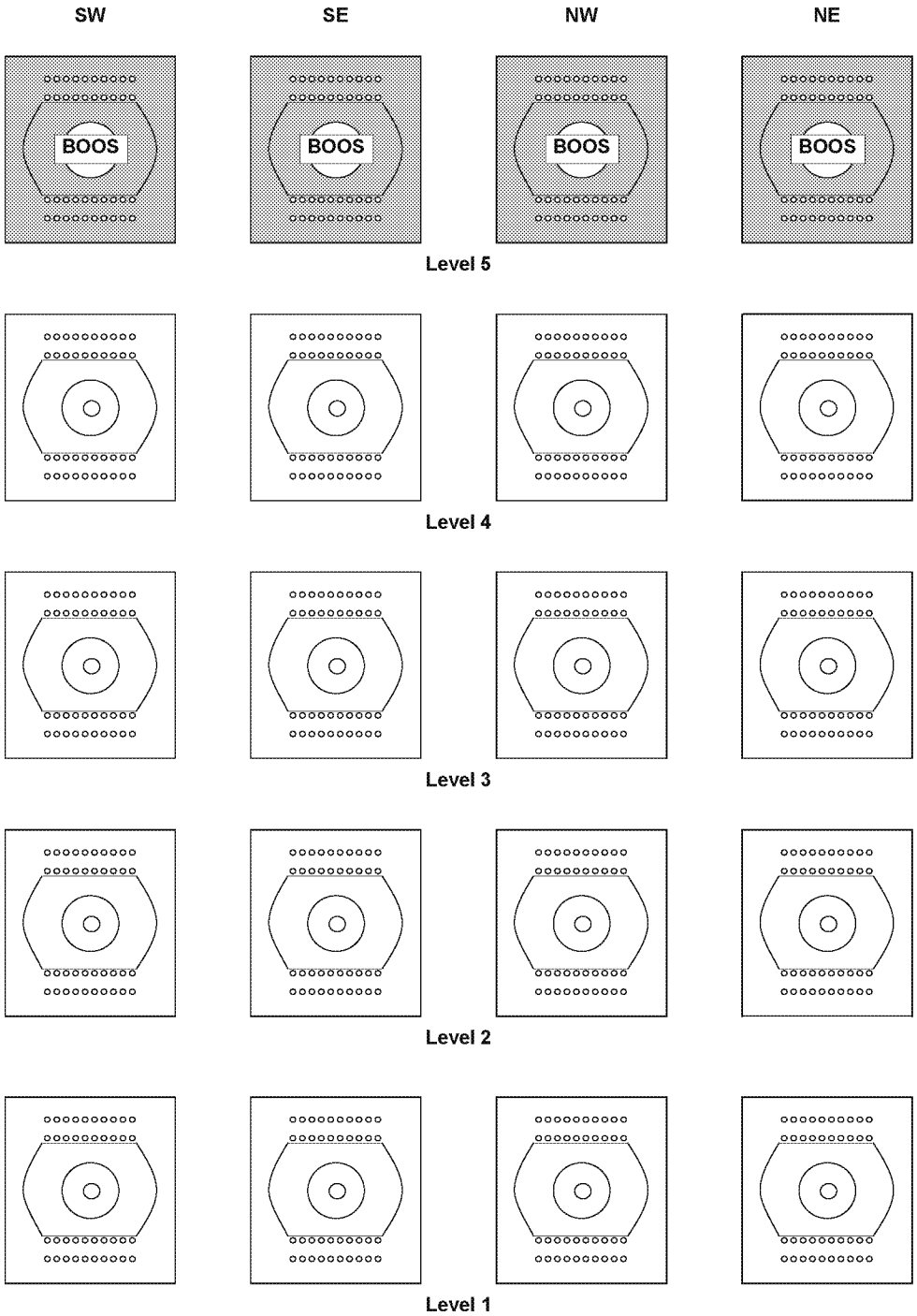


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

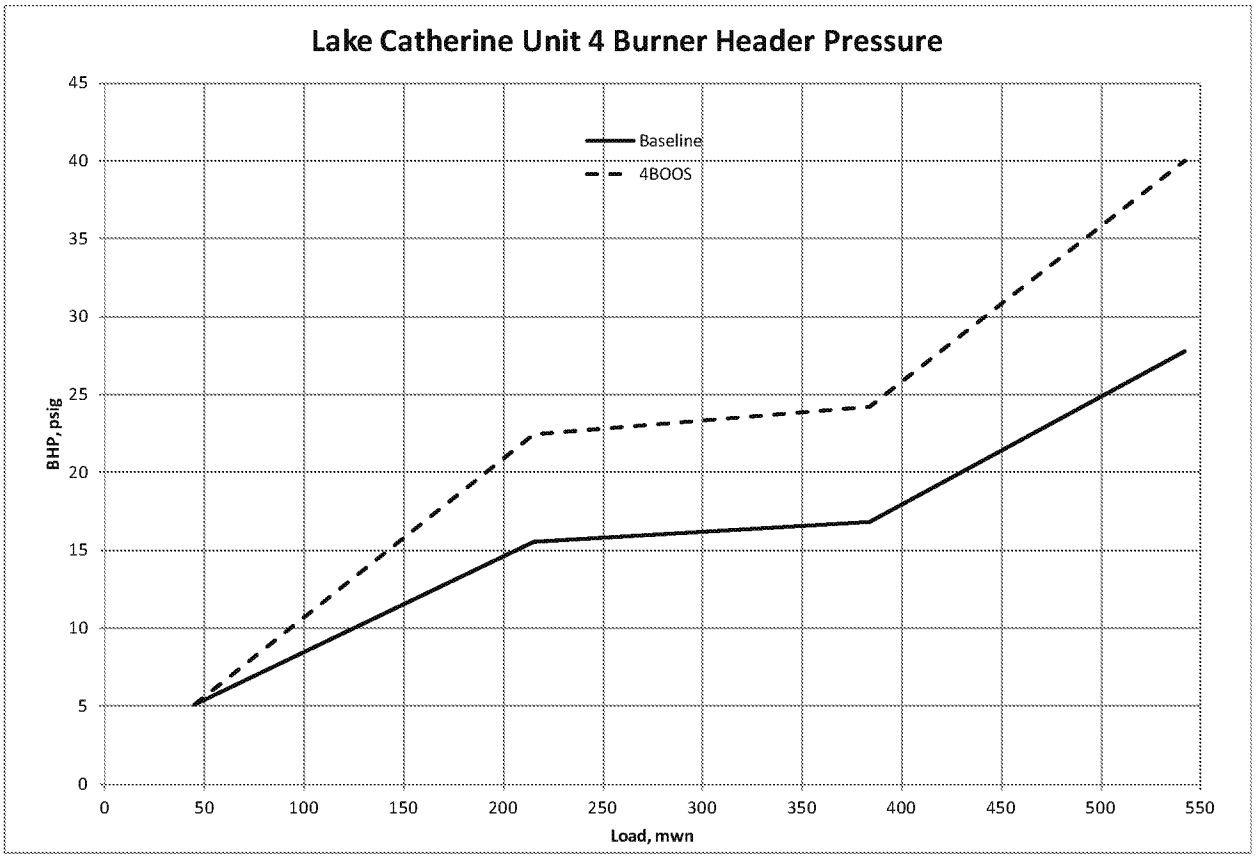
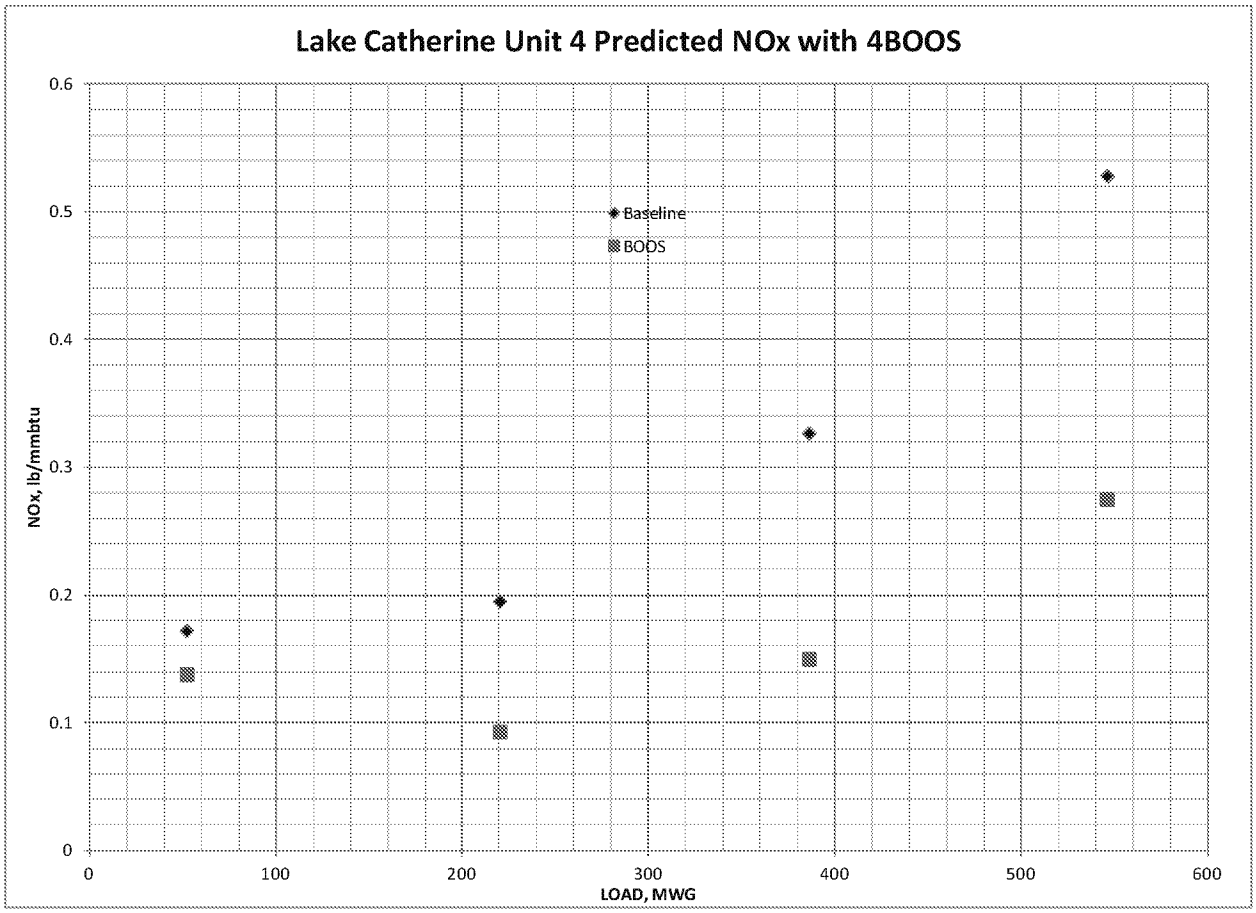


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



Message

From: Agile Development in Government Training Workshop [Training@PotomacForum-AgileInGov.org]
Sent: 10/3/2017 1:04:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: [SPAM] Prepare for New Focus on Agile: Agile Development in Gov-Real World Experiences

- Please Forward to Others in Your Organization Interested in Agile Development for Software Development, Contracting or Other Applications

---

Agile Development in Government Training Workshop IX:

Laying the Right Foundation for Agility Within Your Agency

What Executives, Managers and Staff Need to Know
A "How to" Workshop Discussing Best Practices and Lessons Learned

Wednesday, November 8, 2017
Willard InterContinental Hotel
Washington, D.C.

Link to Potomac Forum Website: www.PotomacForum.org

Government & Industry Invited to Attend

Sponsored by:
Potomac Forum, Ltd
providing training to government since 1982

Previous Eight Agile Workshops
Rated As Excellent By
Government & Industry Students

Potomac Forum Workshops are 100% Training and

Not Sales or Marketing Events

Government Speakers:
Keynote
William (Bill) Pratt
Director, IT Standards & Program Support
Office of the CIO
Department of Homeland Security
(awaiting agency approval)
(Author of the Widely Acclaimed
DHS AGILE Guidebook Used by DHS and Many Other Government Agencies)

Featured Speaker
Jonathan Mostowski
Member of the Defense Digital Service Team,
The White House and Pentagon

Tia Norman
Branch Chief - Agile Maturity & Governance
Office of the CIO
Department of Homeland Security
(awaiting agency approval)

Melissa Cohen
Director, Policy and Programs Group
Center for Medicare Medicaid Services (CMS)

Daniel Levenson
Digital Service Contracting Advisor
Center for Medicare & Medicaid Services (CMS)

Additional Government Speakers
to be Announced Soon

With the current Administration's emphasis on IT Modernization coupled with today's demanding environment and reduced budgets, most Federal agencies are at some level of Agile adoption or transformation to increase efficiencies and meet these challenging demands. However, many would welcome insight into how best to address the cultural issues and other factors contributing to impediments to Agile adoption. Knowing how to achieve success in this process by laying the right foundation will be the key focus of this workshop.

Overview of the Workshop:
Agile Development in Government Training Workshop IX:
Laying the Right Foundation for Agility Within Your Agency is

designed to provide attendees with practical suggestions from other government agencies to address the kinds of challenges to prepare for based on their own experiences with Agile transition approaches that have worked for them; "laying the right foundation". The afternoon government panel will also share their insights on lessons learned based on their real-world experiences as they navigate through their Agile transformation within their own agencies.

What You Will Learn:

- **What typically drives the pockets of resistance in government agencies and how can they be dealt with successfully?**
- **How will my role and responsibilities change, and how can I best prepare myself?**
- **How can we ensure that our contracting for Agile Digital Services is not in conflict with the FAR?**
- **What are some innovative contracting initiatives that are already working for government?**
- **We've already started down the path of Agile adoption. What are some of the commercial best practices that we could adopt in our government agency?**
- **What should we know about selecting and interacting with Agile partners from industry?**
- **What kind of training should my government staff be looking for to best manage the government/vendor relationship on my Agile projects?**

Why You Should Attend:

- As more and more government agencies move to adopt Lean and Agile practices, there must be assurance that they are keeping within the regulatory boundaries unique to the Federal government. Many agencies are already doing this very successfully. This workshop will show you how they are navigating these challenges.

- There are agencies that are eliminating costly mistakes and downtime by successfully adopting Lean and Agile practices. Come and hear their experiences and lessons learned.

- Agile practices not only take technical expertise, but require deep cultural change. Hear from experts and daily practitioners about the importance of managing these cultural challenges and how they are successfully driving cultural change based on their real world experiences.

Who Should Attend:

- **CIOs, CTOs, Federal IT experts**
- **Contracting officers Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their Agencies**
- **Acquisition professionals**
- **Agencies new to adopting Agile projects**
- **Agencies that have already started to adopt Agile practices who want to move to the next level of agility**
  Development and Operations teams facing ongoing challenges to deployment
- **Program and project managers**
- **Agile teams facing ongoing challenges to acquisition**
- **Chief Financial Officers and Staff**
- **Contracting and Acquisition professionals who are or will soon be supporting Agile adoption at their agencies**
- **Project and program managers who want to better understand their role in an Agile environment**
- **Inspector Generals and Staff**
- **Industry Executives, Managers and Staff who support the government**

Workshop for Government and Industry Partners
Press is NOT Permitted to Permit Candid Discussion

CEUs and CLUs Credits
Awarded for Attendance

Team "Learn Together" Reduced Registration Fee

Student Evaluation Comments from Previous Potomac Forum
Agile in Government Training Workshops

I was extremely pleased and will consider Potomac Forum for future raining needs
Lead Contact Specialist
Independent Agency

This workshop was extremely beneficial. I knew very little about the Agile method prior to this workshop and now feel like I can talk about Agile effectively
Investigator
DOJ Agency

The overall workshop was excellent. I have a pretty good understanding of Agile and feel that I'm ready to start a small Agile project
IT Systems Division Chief
DOJ Agency

The workshop as excellent and very informative.
Excellent training session
Branch Chief
Federal Agency

Timely topics, engaging & knowledgeable speakers, good flow, well organized
Business Process Improvement Specialist
Business Process Improvement Specialist
Independent Agency

Educational, informative, enjoyable! Exactly what I wanted
Excellent speakers
Sr Project Manager
Large Government Contractor

Informative and educational. Good examples of implementation and/or risks.
Panel Discussion very beneficial
Sr Projects Officer
Government Agency

It was an excellent gathering with experts and we got to benefit from their experience in real projects
IT Specialist
Independent Agency

Workshop for Government and Industry Partners

Early Bird Reduced Registration Until Oct 15th
Learn Together Team Rates:
Reduced Registration for Multiple Attendees from the same organization

Registration and Information:
www.potomacforum.org

Call: (703) 683-1613
info@PotomacForum.org

Sponsored by:
Potomac Forum, Ltd.
Founded in 1982 as a non-profit educational organization

Potomac Forum, Ltd is Proud to be:
Corporate Partner of
The Association of Government Accountants

Sustaining Partner
Association for Federal Information Resources Management
AFFIRM

Potomac Forum Direct Phone: (703) 683-1613

If this email is not of specific interest to you,
please forward to an associate.

Please DO NOT UNSUBSCRIBE from this
"Agile Development" mailing list.
Potomac Forum offers a wide variety of government related training events
which may be of interest to you in the future.
If you unsubscribe from this "Agile Development" list, you will
not receive future notices for "Agile Development" from this list.

Thank You.

This email was sent to: gunasekara.amanda@epa.gov

Go here to leave this mailing list or modify your email profile.
We respect your right to privacy. View our policy.

Potomac Forum, Ltd.

This email was sent by: **Potomac Forum, Ltd.**
400 North Washington Street , Alexandria , Virginia, 22314 , USA

Message

From: Kime, Robin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=7EF7B76087A6475B80FC984AC2DD4497-RKIME]
Sent: 9/25/2017 6:58:17 PM
To: Jonathan E. Missner [JMissner@steinmitchell.com]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Meeting with the Specialty Equipment Market Association

Hello,
Checking on this. Thx

Sent from my iPhone

On Sep 25, 2017, at 2:18 PM, Jonathan E. Missner <JMissner@steinmitchell.com> wrote:

Hi Robin, because of some recent developments, an opportunity for a phone call with Mandy this week could prove very helpful and may even obviate the need for a live meeting with the full group on Friday. If this is a possibility, can you help set this call up? It would just be me, Chris Kersting and Mandy. And of course anyone Mandy may invite on the call. Best, JON

From: dravis.samantha@epa.gov
When: 10:30 AM - 11:00 AM September 29, 2017
Subject: Meeting with the Specialty Equipment Market Association
Location: DCRoomARN3500/OPEI

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station. Please arrive 10 minutes prior to the meeting with photo IDs to clear Security.
EPA Contact: For an escort from Security to the meeting call (202) 564-4332; for all other matters call Robin Kime (202)564-6587.
Attendees: Jonathan E. Missner and Chris Kersting (CEO of SEMA).
Request: We would like the opportunity to get your advice as we are close to a potential finish line on an important issue that provides a win to the EPA and provides aligned interests. We have been in touch about this before, but a brief overview is below.

The Specialty Equipment Market Association (SEMA) is a trade association comprising of small to medium businesses involved in manufacturing and distributing automotive parts. These parts are intended for installation on racing vehicles as well as street vehicles to improve performance, handling and appearance. The industry is about $39.2 billion in business, has approximately 1 million workers. Racing alone is about a $1.5 billion industry. There are 36 million "customers." The major publisher of car magazines reaches 20 million subscribers. The SEMA Show in Las Vegas has about 160,000 attendees from the industry. No consumers. It is also the largest auto parts show in the world. SEMA also has the PRI Show which is strictly racing, that is, racers, race teams, racing organizations, car manufacturers, etc.
SEMA has worked closely with the EPA to assure that parts used on street vehicles have complied with governmental certification programs demonstrating that such parts do not

adversely emissions. SEMA is the greatest asset available to the EPA in eliminating "defeat devices."

After 40 year of collaboration on important environmental programs, and without warning, the EPA announced that they have and intend to use authority to regulate vehicles used solely for competition as well as parts used solely for racing. This is a clear case of unnecessary, overregulation of an American institution, motorsports, enjoyed by millions of people, responsible for the employment of millions of people and responsible for multiple millions of tax revenues. This is small business. This is a significant example of middle American who have not had a voice in Washington.

SEMA and a coalition of organizations including virtually every motorsports sanctioning organization in the United States concluded this could not stand. SEMA initiated a Petition to the White House in opposition to the EPA action and secured over 100,000 signatures within 24 hours, to our knowledge the largest number of people to participate in the shortest amount of time. SEMA also pursued legislation in the last Congress. The bill, the RPM Act, would make clear that the EPA did not authority to regulate racing, had 120 bipartisan cosponsors in the House and 28 bipartisan cosponsors in the Senate. It was introduced late in a Presidential election year and did not pass the Congress.

The Bill enjoys bi-partisan support at this time and is moving again. At this time, this Bill is currently in the Committee on Environment and Public Works and seems to be moving quickly. We are in need of your valuable advice on this Bill that could move quickly with bi-partisan support. This legislation seeks to address the type of overregulation that earned the ire of the President and EPA Administrator Pruitt.

Contact:

Jonathan E. Missner I Managing Partner
Stein Mitchell Cipollone Beato & Missner LLP
1100 Connecticut Ave, NW Suite 1100
Washington, DC 20036
D 202.661.0956
M 301-503-3322
jmissner@steinmitchell.com

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/13/2017 2:37:28 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Draft RH SIP and supporting docs part 4
Attachments: 18_E1_cov_ltr_9-9-13SWEPCO.pdf; 19_E2_Flint_Creek_BART_Analysis_compiled_September_2013_v4.pdf

Part 4.

Stuart Spencer
Associate Director- Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
Ph. # (501) 682-0750
Fax # (501) 682-0880
E-mail: SPENCER@adeq.state.ar.us
Web: http://www.adeq.state.ar.us

This e-mail and any files transmitted with it are the property of the Arkansas Department of Environmental Quality, and are intended solely for the use of the individual or entity to whom this email is addressed. If you are not the named recipient(s) or otherwise have reason to believe that you have received this message in error, please notify the sender at (501) 682-0750 and delete this message immediately from your computer. Any other use, retention, dissemination, forwarding, printing or copying of this email is strictly prohibited.

AMERICAN ELECTRIC POWER

American Electric Power
1201 Elm Street, Suite 800
Dallas, TX 75270
AEPcom

September 10, 2013

VIA ELECTRONIC SUBMITTAL

Mary Pettyjohn
Arkansas Department of Environmental Quality
5301 Northshore Drive
Little Rock, AR 72118

Dayana Medina
U.S. Environmental Protection Agency, Region 6
Multimedia Planning and Permitting Division
Air Planning Section (6PD-L)
1445 Ross Avenue
Dallas, TX 75202

Re: Application for BART Determination for SO_2 and NOx
At the Flint Creek Power Plant, Gentry, Arkansas (AFIN 04-00107)

Dear Ms. Pettyjohn and Ms. Medina:

Below are the responses to each of the questions/requests sent to Southwestern Electric Power Company (SWEPCO) on August 21, 2013, regarding the cost evaluation and proposed emission levels for NO_X control technologies evaluated in the BART five factor analysis for the Flint Creek Power Plant. We also are providing an updated report that incorporates revisions discussed below.

We have summarized and numbered the questions in your August 21, 2013 email to set off the specific responses. If we have misinterpreted your questions, please let us know.

1. *De-escalation of LNB/OFA and SCR Cost Estimates.*

In the enclosed report, we have revised the cost estimates for LNB/OFA and SCR by de-escalating the total annual cost values by three (3) percent per year to present updated costs on a current (2013/2014) basis.

2. *SCR Equipment Life for Capital Recovery*

In the enclosed report, we have revised the cost estimates for SCR to be based on a 30-year life for capital recovery purposes.

3. *LNB/OFA Equipment Life for Capital Recovery*

In the enclosed report, we have revised the cost estimates for LNB/OFA to be based on a 30-year life for capital recovery purposes.

4. *SCR Cost v. Visibility Benefit*

We agree with EPA's assessment that even after the revisions mentioned above, the visibility benefits of SCR do not justify the cost of control.

4. *Emission Level for LNB/OFA*

SWEPCO has requested a 30-day rolling average limitation of 0.23 lb/MMBtu following installation of the LNB/OFA systems at Flint Creek Station, consistent with EPA's determination of the presumptive BART level for this equipment on this type of electric generating unit. SWEPCO submitted information on anticipated levels of controlled NOx emissions from the manufacturer of the LNB/OFA system in support of its request, which ranged from 0.145 – 0.218 lb/MMBtu based on four-hour tests. SWEPCO also submitted actual controlled NO_X emissions data from similar units. EPA agrees that the PacifiCorp Wyodak unit is the most similar to Flint Creek in terms of its uncontrolled emission rate, and agreed that the NO_X emissions for this unit have been as high as 0.21 lb/MMBtu following installation of similar equipment from the same manufacturer. Welsh Unit 2, which is a sister unit to Flint Creek, has also installed equipment from the same manufacturer, and since May of 2005 has measured emissions as high as 0.191 lb/MMBtu.

NO_X emissions are primarily produced as part of the combustion process as a function of the temperature in the combustion zone, and can vary significantly from unit to unit. Pursuing the lowest achievable NO_X emission rates at an electric generating unit can have adverse consequences, including accelerated deterioration of boiler tubes, leading to expensive and time-consuming repairs. In addition, NO_X production is inversely related to the production of CO from the boiler, and pursuing a NO_X rate lower than the requested rate could increase CO production to the point that Flint Creek would need to accept restrictions on its maximum output rating and capacity factor in order to simultaneously achieve both its CO and NO_X limits.

While the requested emission rate is slightly higher than the highest averages achieved at similar units, some margin for compliance is necessary and desirable to accommodate the inherent variability of fuel supply, boiler tune-ups, and attributable to ordinary wear and tear of the equipment. Although the measured performance of Wyodak and Welsh Unit 2 confirms the likely achievability of the requested rate, their current permitted emission limits are as high or higher than the requested rate (0.23 and 0.36 lb/MMBtu, respectively), further confirming that some compliance margin is appropriate. Accordingly, ADEQ should find that the BART

EPA-HQ-2018-002296

emission rate is 0.23 lb/MMBtu, consistent with EPA's determination of presumptive BART and prior BART determinations for similar units.

We hope that this information will satisfactorily address the questions and concerns outlined in the August 21, 2013 email. Please contact me at (214) 777-1113 to provide any additional information you may require.

Sincerely,

Kris Gaus, QEP
Environmental Specialist
Air Quality Services

File:FLC.10.90.50.10.2013

ED_002110_00032805-00003

BART FIVE FACTOR ANALYSIS

FLINT CREEK POWER PLANT

GENTRY, ARKANSAS (AFIN 04-00107)

Prepared By:

TRINITY CONSULTANTS, INC.
120 East Sheridan, Suite 205
Oklahoma City, Oklahoma 73104
(405) 228-3292

TRINITY CONSULTANTS, INC.
977 Ridge Drive, Suite 380
Lenexa, Kansas 66219
(913) 894-4500

In conjunction with:

AMERICAN ELECTRIC POWER SERVICE CORPORATION
PO Box 660164
Dallas, Texas 72566
(214) 777-1113

for the

SOUTHWESTERN ELECTRIC POWER COMPANY
FLINT CREEK POWER PLANT
21797 SWEPCO Plant Road
Gentry, Arkansas 72734

Trinity Project Nos. 113701.0022 & 123701.0038

September 2013
Version 4

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INTRODUCTION AND BACKGROUND 2-1

3. MODELING METHODOLOGIES AND PROCEDURES 3-1
3.1 CALMET AND CALPUFF 3-1
3.2 CALPOST 3-1

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT 4-1
4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES 4-1
4.2 BASELINE VISIBILITY IMPAIRMENT 4-2

5. SO_2 BART EVALUATION 5-1
5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES 5-1
5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES 5-1
5.2.1 DRY SORBENT INJECTION 5-1
5.2.2 DRY SCRUBBER 5-2
5.2.3 WET SCRUBBER 5-2
5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS .. 5-3
5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS 5-3
5.4.1 COST OF COMPLIANCE 5-4
5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS 5-7
5.4.3 REMAINING USEFUL LIFE 5-7
5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS 5-7
5.6 PROPOSED BART FOR SO_2 5-10
5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS 5-10

6. NO_X BART EVALUATION 6-1
6.1 CROSS-STATE AIR POLLUTION RULE, ... 6-1
CLEAN AIR INTERSTATE RULE, AND BART 6-1
6.2 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES 6-2
6.3 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES 6-2
6.3.1 COMBUSTION CONTROLS 6-3
6.3.1.1 Flue Gas Recirculation (FGR) 6-3
6.3.1.2 Overfire Air (OFA) 6-3
6.3.1.3 Low NO_X Burners 6-3
6.3.2 POST COMBUSTION CONTROLS 6-4
6.3.2.1 Selective Catalytic Reduction 6-4
6.3.2.2 Selective Non-Catalytic Reduction 6-4
6.4 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS .. 6-5
6.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS 6-5

6.5.1 COST OF COMPLIANCE 6-6
6.5.2 ENERGY IMPACTS & NON-AIR IMPACTS 6-10
6.5.3 REMAINING USEFUL LIFE 6-10
6.6 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS 6-10
6.7 PROPOSED BART FOR NO_X 6-1

7. PM_{10} BART EVALUATION 7-1

APPENDIX A .....

APPENDIX B .....

APPENDIX C .....

LIST OF TABLES

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 (2001-2003) 1-1

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION 3-2

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS 3-3

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS 3-3

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS 3-3

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS) 4-1

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BOILER (2001-2003) 4-2

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 5-1

TABLE 5-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES 5-3

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS 5-5

TABLE 5-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF WET SCRUBBING 5-6

TABLE 5-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF NIDS 5-6

TABLE 5-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS 5-8

TABLE 5-7. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003) 5-9

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01 6-2

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES 6-5

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 NO_X CONTROLS 6-8

TABLE 6-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA 6-9

TABLE 6-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA PLUS SNCR 6-9

TABLE 6-6. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING SCR 6-9

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA FOR NO_X CONTROL 6-11

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT SCR FOR NO_X CONTROL 6-11

TABLE 6-9. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA + SNCR FOR NO_X CONTROL 6-11

TABLE 6-10. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON SN-01 (2001-2003) 6-12

1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) for Southwestern Electric Power Company's (SWEPCO's)[1] electric generating unit at the Flint Creek Power Plant (SN-01). SN-01 is a dry bottom wall-fired boiler with a nominal design maximum heat input of 6,324 million British thermal units per hour (MMBtu/hr) that burns primarily low sulfur western coal. The unit has a nominal generating capacity rating of 558 MW and commenced commercial operation in 1978. It is currently equipped with an electrostatic precipitator and low NO_X burners.

Based on modeling performed for this analysis, cumulative emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mean diameter smaller than ten microns (PM_{10}) from SN-01 are predicted to cause or contribute greater than 0.5 deciviews (Δdv) of visibility impairment in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING).

A summary of the existing visibility impairment attributable to SN-01 based on the default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on modeling conducted by Trinity Consultants (Trinity) using actual emissions data based on a combination of stack testing and CEMS as further described in Section 4 of this report.

TABLE 1-1. EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 (2001-2003)

	Caney Creek Wilderness		Upper Buffalo Wilderness		Hercules Glades Wilderness		Mingo Wilderness	
	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv	98th % Δdv	Days > 0.5 Δdv
AEP Flint Creek SN-01	0.963	48	0.965	63	0.657	47	0.631	20

Trinity used the EPA's BART guidelines in 40 CFR Part 51[2] and other recent EPA guidance to determine BART for SN-01. Trinity conducted a five-step analysis to determine BART that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and document the results;
5. Evaluating visibility impacts.

[1] Southwestern Electric Power Company (SWEPCO) is an owner and the operator of the Flint Creek Power Plant, and a subsidiary of American Electric Power Company, Inc. (AEP). American Electric Power Service Corporation is a subsidiary of AEP that provides legal, accounting, engineering, and other services to the utility operating companies in the AEP system, including SWEPCO. SWEPCO and the Service Corporation are referred to generically as AEP throughout this report.

[2] The BART guidelines were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 6, 2005.

Based on the five-step analysis, the following were determined to be BART:

- SO_2 – The BART analysis concluded that the installation of a dry scrubber and baghouse (e.g., Novel Integrated Deacidification System [NIDS] technology) constitutes BART. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day.
- NO_X – EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_x to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART.[3] Subsequently, CSAPR was vacated, and the Clean Air Interstate Rule (CAIR) remains in effect until an acceptable replacement rule is promulgated.[4] If CSAPR is upheld and implemented in Arkansas, SWEPCO will rely on CSAPR to satisfy its regional haze obligations at SN-01. If CSAPR is vacated and CAIR remains in effect, EPA's prior determination that the reductions provided under CAIR's seasonal NO_X trading program provide greater visibility improvements than BART should allow SWEPCO to rely on the seasonal CAIR program to satisfy its NO_X obligations under BART.[5]

  In the alternative, SWEPCO has evaluated the cost-effectiveness and visibility improvement of candidate BART controls at SN-01. The visibility improvements associated with the addition of NO_X controls at SN-01 are minimal, and the cost-effectiveness values for all control options exceed the values previously determined to be reasonable in EPA's presumptive BART analysis. However, visibility improvements consistent with the modeled values used in CENRAP's analysis for the interstate transport portion of Arkansas's Regional Haze SIP obligations can be achieved with the addition of LNB/OFA, and this control option is proposed as BART for SN-01. If ADEQ determines that SWEPCO cannot rely on CAIR or CSAPR as an alternative to BART, the proposed BART emission rate for NO_X at SN-01 is 0.23 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day based on the application of LNB/OFA controls.
- PM_{10} – A BART determination for PM_{10} at SN-01 was approved in EPA's March 12, 2012 final rule based on the existing ESP and a BART emission rate of 0.1 lb/MMBtu.[6]

---

[3] "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans" 77 Fed. Reg. 33651 (June 7, 2012).

[4] *EME Homer City Generation, L.P., et al., v. United States Environmental Protection Agency, et al.*,EPA. Case No. 11-1302 (and consolidated cases), *Opinion* (D.C. Cir Aug. 21, 2012).

[5] "Regional Haze Regulations and Best Available Retrofit Technology (BART) Guidelines, 70 Fed. Reg. 39104, 39143 (July 6, 2005).

[6] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background[7]. Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *"... an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by... [a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls
2. Cost of controls

[7] Note this is a change from the ADEQ protocol with the 2006 CENRAP data, as the original analysis for Arkansas reviewed the "High First High" impacts rather than the 98th percentile impacts

3. Energy and non-air quality environmental impacts
4. Remaining useful life of the source
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control technologies;
3. Evaluate the control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results;
5. Evaluate visibility impacts

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above for each VAP.

SN-01 meets the three BART-eligibility criteria described above, and the existing visibility impairment attributable to SN-01 is greater than 0.5 dv in at least one Class I area. Thus, SN-01 is subject to BART. The details of the SN-01 existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by SN-01 include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particle matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_x, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for the Central States Regional Air Planning Association (CENRAP). The CALMET data and parameters are based on the protocol included in Appendix C. Note that the protocol included in Appendix C summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources. In addition, several sources in Texas used the CALMET data that was generated in accordance with the protocol in their BART analyses.

3.2 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The 2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI(\text{dv}) = 10 \ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta dv = 10 * \ln\left[\frac{b_{ext,\ background} + b_{ext,\ source}}{b_{ext,\ background}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[NH_4(SO_4)_2]_{Small} + 4.8 f_L(RH)[NH_4(SO_4)_2]_{Large} + \\ 2.4 f_S(RH)[NH_4NO_3]_{Small} + 5.1 f_L(RH)[NH_4NO_3]_{Large} + \\ 2.8[OC]_{Small} + 6.1[OC]_{Large} + 10[EC] + 1[PMF] + 0.6[PMC] + \\ 1.4 f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[NO_2] \end{array}$$

Visibility impairment predictions for SN-01 relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 3-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$	NH_4NO_3	OM	EC	Soil	CM	Sea Salt	Rayleigh (Mm^{-1})
Caney Creek Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Upper Buffalo Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Hercules Glades Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.02	11
Mingo Wilderness	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Hercules Glades Wilderness	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
Mingo Wilderness	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
Hercules Glades Wilderness	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Mingo Wilderness	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Upper Buffalo Wilderness	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
Hercules Glades Wilderness	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
Mingo Wilderness	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

4. EXISTING EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the existing (i.e. baseline) visibility impairment attributable to SN-01 based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on 2001-2003 continuous emissions monitoring system (CEMS) data. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[8]. Specifically, the NPS workbook shows the following baseline distribution for the PM species:

- Coarse PM (PM_C) = 33.8 %
- Fine soil (modeled as PM_F) = 26.1 %
- Fine elemental carbon (modeled as EC) = 1.0 %
- Organic condensable PM (modeled as SOA) = 7.8 %
- Inorganic condensable PM (modeled as SO_4) = 31.3 %

Per EPA's request,[9] an SO_4 emission rate was independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[10] This SO_4 rate was used in the modeling instead of the rate resulting from the NPS-based breakdown.

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Source	SO_2[11] (lb/hr)	SO_4 (lb/hr)	NO_X[12] (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	4,728.4	3.1	1,945.0	65.1	50.1	15.1	1.9

[8] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 192.5 lb/hr, heat value of 8,500 Btu/lb, sulfur content of 0.31%, ash content of 4.9%.

[9] E-mail from Dayana Medina (EPA) to Mary Pettyjohn (ADEQ), February 8, 2013, and phone conversation with Michael Feldman (EPA), February 26, 2013.

[10] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Version 2010a. EPRI, Palo Alto, CA: 2010. 1020636.

[11] Hourly rate was derived from EPA's Clean Air Market Database (CAMD) daily rates of 113,482 lb/day.

[12] Hourly rate was derived from EPA's Clean Air Market Database (CAMD) daily rates of 46,680 lb/day.

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to determine the visibility impairment attributable to SN-01 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.

Table 4-2 provides a summary of the modeled visibility impairment attributable to SN-01 at CACR, UPBU, HERC, and MING based on the emission rates shown in Table 4-1. Note that all of the CALMET, CALPUFF, and CALPOST modeling files are included as part of the electronic files submitted with this document.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BOILER (2001-2003)

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	1.318	0.609	19	62.49	34.95	1.00	1.55
2002	1.165	0.689	10	60.43	35.25	1.72	2.60
2003	1.298	0.963	19	70.90	27.64	0.62	0.85
Upper Buffalo Wilderness							
2001	1.732	0.955	22	53.01	45.08	1.16	0.74
2002	2.426	0.965	18	96.29	2.75	0.96	0.00
2003	1.394	0.670	23	89.90	5.4	2.74	1.97
Hercules Glades Wilderness							
2001	1.418	0.643	19	76.92	22.4	0.69	0.00
2002	1.364	0.627	15	43.49	51.71	2.08	2.72
2003	2.103	0.657	13	47.91	49.69	1.19	1.21
Mingo Wilderness							
2001	1.28	0.631	11	90.97	8.59	0.42	0.01
2002	0.841	0.424	6	93.66	5.94	0.40	0.00
2003	1.488	0.393	3	38.60	59.69	1.07	0.64

5. SO_2 BART EVALUATION

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from SN-01, the BART analysis is specific to emissions of SO_2.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for SN-01 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as SN-01 currently uses a low sulfur fuel and would not achieve significant additional reductions through alternative coal supplies.

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01

SO_2 Control Technologies
Dry Sorbent Injection
Dry Scrubber
Wet Scrubber

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a sorbent into the exhaust gas stream where SO_2 reacts with and becomes entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[13] This control is a technically feasible option for the control of SO_2 from SN-01.

[13] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

5.2.2 DRY SCRUBBER

In a dry scrubber, an alkaline reagent (usually lime) and water is introduced into the flue gas stream, where it reacts with SO_2 to form calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before leaving the scrubber outlet. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Existing dry scrubber control efficiencies range from 60 to 95 percent.[14] This is a technically feasible option for the control of SO_2 from SN-01.

There are various designs of dry scrubbing systems. In the spray dryer absorber (SDA) design, a fine mist of lime slurry is atomized into an absorption vessel where the SO_2 is absorbed by the slurry droplets. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. Circulating dry scrubbing (CDS) is another type of dry scrubbing. In the CDS process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of SO_2 in the flue gas with the dry lime particles. As with SDA, the mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust gas and collected with a fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

Novel Integrated Deacidification (NID) technology is another particular type of dry scrubber. Hydrated lime is added to recirculated dust in the mixer of the NID system. The solids are sprayed with a thin layer of water in the mixer before being transported to the reactor. The amount of water added is only a few percent which means that the dust remains dry. Hydrated lime reacts with SO_2 in the NID-reactor and leads to the formation of calcium sulfite and calcium sulfate. The flue gas entrained with dry dust material enters the fabric filter where the dust material is captured and clean air is released to atmosphere. Most of the solid material captured is reused in the system. The system has a high recirculation ratio of the dry dust material. Discussions with vendors have indicated that an outlet emission rate of 0.06 lb/MMBtu at Flint Creek will be achievable with the NID technology evaluated. A rate of 0.06 lb/MMBtu represents a 92% control from the baseline 30-day average rate of 0.75 lb/MMBtu. The controlled rate was quoted as an outlet rate rather than a straight percent control.

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an electrostatic precipitator (ESP). The liquid-to-gas ratio is such that the exhaust gas is fully saturated with water and

[14] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

has a similar appearance to a cooling tower exhaust. Similarly to the chemistry illustrated above for dry scrubbing, the SO_2 in the gas stream is absorbed by water and reacts with the lime or limestone slurry to form calcium sulfite or calcium sulfate. Wet lime scrubbing is capable of achieving 80-95 percent control when used with lower sulfur coals like those burned at SN-01.[15] This control is a technically feasible option for the control of SO_2 from SN-01.

5.3 Rank of Technically Feasible SO_2 Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the visibility affecting pollutants (VAP). Table 5-2 provides a ranking of the control levels for the controls listed in the previous section for SN-01.

Table 5-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Controlled Emission Rate (lb/MMBtu)	Estimated Control Efficiency
Wet Scrubbing	0.04	95%
Dry Scrubbing, e.g., NID	0.06	92%
Dry Sorbent Injection	0.30	60%

5.4 Evaluation of Impacts for Feasible SO_2 Controls

A shown in Table 5-2, wet scrubbing can achieve a 95% reduction in SO_2 while dry scrubbing or NID can achieve a 92% reduction in SO_2, and these technologies are the most effective technologies at reducing SO_2. Step four of the BART analysis procedure is the impact analysis. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

[15] Ibid.

AEP is providing Step 4 and Step 5 evaluations specific to the NID technology as well as WFGD. Also, AEP is providing a discussion of energy and non-air quality impacts of wet scrubbing versus the NID technology.

5.4.1 COST OF COMPLIANCE

Control Costs

The capital and operating costs of WFGD and NID used in the cost effectiveness calculations were estimated based on EPA's Air Pollution Control Cost Manual supplemented with vendor and site-specific information where available. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the capital and operating cost estimates are provided in Appendix A of this report.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate is the average rate from 2001-2003, as reported by AEP in their air emission inventories. The controlled annual emission rates were based on lb/MMBtu levels believed to be achievable for the control technology multiplied by the baseline heat input in MMBtu/yr to the boiler. The baseline heat input is based on the 2001-2003 average daily heat input for SN-01 as determined from the EPA's Clean Air Markets Database (CAMD), divided by 24 hours in a day times an estimated 7,752 hours per year, the average number of operating hours from 2001-2003.

Cost Effectiveness

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 5-3 indicates that the cost effectiveness of the wet scrubber at an SO_2 rate of 0.04 lb/MMBtu is approximately $4,900 per ton of SO_2 removed. The cost effectiveness in dollars per deciview of visibility is over $476 million/dv across the Class I areas, as seen in Table 5-4.

By comparison, Table 5-3 shows the cost effectiveness of a NIDS at an SO_2 rate of 0.06 lb/MMBtu is approximately $3,800 per ton of SO_2 removed. The cost effectiveness in dollars per deciview is approximately $368 million/dv across the Class I areas, as seen in Table 5-5. Table 5-3 shows that the wet scrubber is approximately $35,000/ton incrementally more expensive than the dry scrubber.

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS

Control Technology	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input	Controlled Emission Rate	SO_2 Reduced	Capital Cost	Capital Recovery + Other Indirect Annual Costs	Annual Fixed O&M	Annual Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
NIDS	11,641.00	0.06	37,344,783	1,120.34	10,520.66	281,738,024	30,763,370	205,825	9,478,894	40,448,089	3,845	-
Wet Scrubber	11,641.00	0.04	37,344,783	746.90	10,894.10	374,427,351	40,884,248	205,825	12,502,590	53,592,663	4,919	35,198

TABLE 5-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF WET SCRUBBING

Class I Area	Baseline 98th Percentile Δdv	WFGD Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual WFGD Cost	$/dv
Caney Creek	0.963	0.334	0.629	53,592,663	$ 85,202,962
Hercules-Glades	0.657	0.305	0.352	53,592,663	$ 152,251,885
Mingo	0.631	0.208	0.423	53,592,663	$ 126,696,604
Upper Buffalo	0.965	0.488	0.477	53,592,663	$ 112,353,592

TABLE 5-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 SO_2 CONTROLS OF NIDS

Class I Area	Baseline 98th Percentile Δdv	NID Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual NID Cost	$/dv
Caney Creek	0.963	0.348	0.615	40,448,089	$ 65,769,251
Hercules-Glades	0.657	0.312	0.345	40,448,089	$ 117,240,838
Mingo	0.631	0.217	0.414	40,448,089	$ 97,700,699
Upper Buffalo	0.965	0.501	0.464	40,448,089	$ 87,172,606

5.4.2 Energy Impacts and Non-Air Quality Impacts

Wet scrubbing is expected to achieve a slightly higher level of control of SO_2 emissions compared to the proposed NID technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized before landfilling. Wet scrubbing systems have increased power requirements and increased reagent usage over dry scrubbers. Wet scrubber-controlled systems also have the potential for increased particulate and sulfuric acid mist releases. Thus, from an overall environmental perspective, dry scrubbing (i.e., NID technology) is superior to wet scrubbing.

5.4.3 Remaining Useful Life

The remaining useful life of SN-01 does not impact the annualized capital costs because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period, which is 30 years based on EPA cost estimates.

5.5 Evaluation of Visibility Impact of Feasible SO_2 Controls

A final impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the controlled emission rates. Section 4 of this report documents the existing visibility impairment attributable to SN-01. In order to assess the visibility improvement associated with the considered control options, the controlled SO_2 emission rates were modeled using CALPUFF.

The SO_2 emission rate associated with the NID for SN-01 is detailed as follows:

$$P * HI = 379.44 \text{ lb/hr}$$

Where:
P (controlled emission level) = 0.06 lb/MMBtu
HI (hourly heat input) = 6,324 MMBtu/hr

Table 5-6 summarizes the lb/hr emission rates that were modeled to reflect the addition of NIDS as a control at Flint Creek. The SO_2 rate was developed from the controlled rate of 0.06 lb/MMBtu and the boiler heat input of 6,324 MMBtu/hr. The SO_4 emission rate was determined assuming the reduction in SO_4 from the baseline case is proportional to the reduction in SO_2 from the baseline case to the controlled case (92%). The NIDS will have co-effects on some of the acid gases. The control of H_2SO_4 will result in fewer sulfates. The NO_X emission rate was modeled at the baseline rate. The NIDS involves the use of a baghouse. The change from the current ESP to baghouse will result in changes in PM speciation. All other rates that changed from the baseline case were determined using the National Parks Services (NPS) speciation spreadsheets for dry bottom boilers burning pulverized coal using only fabric filter for emissions control.

Table 5-6 also summarizes the emission rates that were modeled to reflect the addition of a wet scrubber on SN-01, at an outlet emission rate of 0.04 lb/MMBtu. The SO_2 rate was developed by multiplying the controlled level of 0.04 lb/MMBtu by the boiler heat input of 6,324 MMBtu/hr. The NO_X emission rates were modeled at the baseline rates. The PM rates that changed from the baseline case were determined using the NPS speciation spreadsheets for dry bottom boilers burning pulverized coal using only fabric filter for emissions control. The SO_4 rates were calculated using the same EPRI methodology used for the baseline case.

TABLE 5-6. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS

Control Technology	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_x (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
NIDS	379.4	0.004	1,945.0	35.2	33.9	24.4	1.3
Wet Scrubber	253.0	0.11	1,945.0	35.2	33.9	24.4	1.3

Comparisons of the existing visibility impacts and the visibility impacts based on the NIDS, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 5-7.

TABLE 5-7. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
NIDS	0.753	0.348	6	1.474	0.501	13	0.882	0.312	5	0.694	0.217	4
Post Control Improvement	*0.565*	*0.615*	*42*	*0.952*	*0.464*	*50*	*1.221*	*0.345*	*42*	*0.794*	*0.414*	*15*
Wet Scrubber	0.746	0.334	5	1.446	0.488	11	0.845	0.305	5	0.677	0.208	4
Post Control Improvement over NIDS	*0.007*	*0.014*	*1*	*0.028*	*0.013*	*2*	*0.037*	*0.007*	*0*	*0.017*	*0.009*	*0*

Note: The visibility improvement shown in the table has been calculated from baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled impacts shown in the table, the visibility improvement calculated from the baseline and controlled impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-7, based on visibility predictions from the CALPUFF modeling system, the operation of a dry scrubber will result in up to a 0.647 Δdv improvement (98th percentile basis) (depending on the Class I area) to the existing visibility impairment attributable to SN-01. By comparison, wet scrubbing does not add additional visibility improvement for SN-01 over dry scrubbing. The reason wet scrubbing, despite the lower SO_2 emission rate, does not produce greater visibility improvement is because it results in other visibility impairing emissions.[16]

5.6 PROPOSED BART FOR SO_2

SWEPCO is proposing that the SO_2 BART emission rate for SN-01 be 0.06 lb/MMBtu, based on the installation and operation of the NID technology. AEP is proposing to meet this limit calculated as a 30-day rolling average over each boiler operating day. Compliance will be demonstrated using data from the existing continuous emissions monitoring systems (CEMS).

The visibility improvement attributable to SN-01 through the use of the NIDS ranges from 48.1% to 65.6% across the affected Class I areas (98th percentile basis). This level of improvement is achievable at a cost effectiveness of approximately $3,800 per ton of SO_2 removed. By comparison, wet scrubbing is incrementally more expensive and offers less visibility improvement overall. In addition, the adverse environmental impacts from the use of wet scrubbing, including an increase in particulate and sulfuric acid mist emissions as well as increased water and energy usage and wastewater to be treated, make dry scrubbing a more appealing option.

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

The BART emission level proposed for SN-01 is among the most stringent BART emission levels approved for any coal-fired generating unit over the last two years. In Oklahoma, for similar boilers, EPA determined BART to be 0.06 lb/MMBtu achieved through use of dry scrubbers.[17] In Nebraska[18] at the Gerald Gentleman Station, BART for SO_2 was also determined to be 0.06 lb/MMBtu achieved through use of dry scrubbers. These similar units provide a good comparison of emission levels achievable through similar control technology. Levels lower than 0.06 lb/MMBtu have been considered, but rejected based on lack of operating experience on retrofit units, the incremental cost of additional reductions, and the limited incremental visibility improvement associated with those costs. AEP has no data to suggest that lower emission levels are sustainably achievable with the NID technology in a retrofit application, and has not been guaranteed any better performance by equipment vendors. All of these reasons support rejecting any lower emission level for SN-01.

Other BART determinations have resulted in higher emission limitations. For example, in Alabama[19] a smaller EGU was allowed an emission limitation of 0.47 lb/MMBtu through use of flue sorbent injection or comparable technologies. In Arizona[20], SO_2 BART was determined to be in the range of

---

[16] Wet scrubbers have less affinity for acid mist than dry scrubbers; thus, sulfate particles that form from sulfuric acid in the stack will be lower for dry scrubbers than wet scrubbers. AEP's best understanding of the reason wet scrubbing does not produce greater visibility improvement that drying scrubbing, despite the lower SO_2 rate, is that the SO_4 rate associated with wet scrubbing is higher.

[17] 77 Fed. Reg. 16168 (March 22, 2011).

[18] 77 Fed. Reg. 40150 (July 6, 2012).

[19] 77 Fed. Reg. 11937 (Feb. 28, 2012).

[20] 77 Fed. Reg. 42834 (July 20, 2012).

0.08 – 0.15 lb/MMBtu from existing wet scrubbers. An EGU in Colorado[21] has a proposed BART emission rate of 0.13 lb/MMBtu through use of dry scrubbing. It is interesting to note that a lower emission rate of 0.09 lb/MMBtu was evaluated and determined not reasonable due to the little visibility improvement as compared to the higher costs between scrubbing at these two rates.

In other determinations, such as Illinois[22], the control technology was not stated in the BART determination but the SO_2 rate determined to be BART was in the range of 0.11 – 0.23 lb/MMBtu, dependent upon boiler type and averaging considerations. SO_2 BART in Kansas[23] was achieved through "scrubbing" with an emission limitation of 0.10 lb/MMBtu for one boiler and through wet scrubbing with an emission limitation of 0.15 lb/MMBtu for another. An EGU in Montana[24] similar to AEP's SN-01 has a BART emission rate of 0.08 lb/MMBtu.

The proposed SO_2 BART emission rate is equivalent to the most stringent rates previously approved by EPA, is consistent with the design specifications for this equipment, and results in significant visibility improvement in the affected Class I areas. The SO_2 emission rate of 0.06 lb/MMBtu should be adopted as BART for SN-01.

[21] 77 Fed. Reg. 18052 (March 26, 2012).
[22] 77 Fed. Reg. 3966 (Jan. 26, 2012).
[23] 77 Fed. Reg. 52604 (Aug. 23, 2011).
[24] 77 Fed. Reg. 23988 (April 20, 2012).

6.1 CROSS-STATE AIR POLLUTION RULE, CLEAN AIR INTERSTATE RULE, AND BART

On June 7, 2012 EPA published a final rule allowing states participating in the Cross-State Air Pollution Rule (CSAPR) trading program to use CSAPR to satisfy BART. Arkansas is one of the states with units subject to CSAPR that will participate in a NO_X trading program during the ozone season. EPA commented that "NO_X control in the five ozone season-only states is achieved predominantly by combustion controls."[25] Due to the nature of combustion controls, plants typically keep combustion controls in place and running year-round, even if emission limitations are seasonal. Although Arkansas is an ozone season-only state, combustion controls would run anytime the unit is in operation. However, on August 21, 2012, the D. C. Circuit Court of Appeal issued a decision vacating CSAPR and ordering EPA to continue to implement the Clean Air Interstate Rule (CAIR) until a new rule is adopted to replace it. The Court's decision will not be effective until the time for filing rehearing petitions has passed, or any filed petitions for rehearing have been considered by the Court.[26] If CSAPR is upheld and implemented in Arkansas, SWEPCO proposes rely on CSAPR to satisfy its regional haze obligations at SN-01.

Prior to adopting CSAPR, EPA issued a rule confirming that CAIR provides greater reasonable progress toward the national visibility goal than application of BART for NO_X emissions at BART-eligible sources.[27] Since EPA has made the determination that CAIR reductions provide better progress than BART, and Arkansas has adopted the CAIR requirements into the Arkansas SIP,[28] SWEPCO should be entitled to rely upon CAIR to satisfy its obligations for NO_X reductions at SN-01, if CSAPR is vacated in accordance with the D. C. Circuit's opinion.

In the alternative, SWEPCO has evaluated the cost-effectiveness and visibility improvement of candidate BART controls at SN-01. The visibility improvements associated with the addition of NO_X controls at SN-01 are minimal, and the cost-effectiveness values for all control options exceed the values previously determined to be reasonable in EPA's presumptive BART analysis. However, visibility improvements consistent with the modeled values used in CENRAP's analysis for the interstate transport portion of Arkansas's Regional Haze SIP obligations can be achieved with the addition of newer generation LNB/OFA systems, and are proposed as BART for SN-01. If ADEQ determines that SWEPCO cannot rely on CAIR or CSAPR as an alternative to BART, the proposed BART emission rate for NO_X at SN-01 is 0.23 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day based on the application of LNB/OFA controls.

---

[25] "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determination, Limited SIP Disapprovals, and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012).

[26] *EME Homer City v. EPA,* Case No. 11-1302 and consolidated cases, *Opinion*, (D.C. Cir. Aug. 21, 2012).

[27] 70 Fed. Reg. 39104, 39136-37, and 39143 (July 6, 2005).

[28] APC&EC Reg. 19.1401 *et seq.*; approved at 72 Fed. Reg. 54556 (Sept. 26, 2007).

6.2 Identification of Available Retrofit NO_X Control Technologies

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In a wall-fired boiler, such as SN-01, burners are mounted in the boiler walls, producing discrete flames in the furnace. In tangentially-fired boilers, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore baseline NO_X emission rates can vary significantly from plant to plant due to method of firing and also several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1 for SN-01.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

Table 6-1. Available NO_X Control Technologies for SN-01

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Overfire Air (OFA) Low NO_X Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.3 Eliminate Technically Infeasible NO_X Control Technologies

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1. Control ranges were developed using a combination of literature control ranges and efficiencies. Because many controlled emission levels from literature were higher than the baseline NO_X rate at SN-01, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.3.1 COMBUSTION CONTROLS

6.3.1.1 FLUE GAS RECIRCULATION (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the NO_X control range for coal fired boilers with FGR is approximately 5-25% for coal fired boilers, or 0.23-0.29 lb/MMBtu from SN-01.[29] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.2 OVERFIRE AIR (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed. OFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%, or 0.28-0.29 lb/MMBtu from SN-01.[30] This control is a technically feasible option for the control of NO_X from SN-01.

6.3.1.3 LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[31] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_x formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_x formation.

---

[29] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

[30] Ibid.

[31] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

The estimated NO_X control range for LNBs on coal boilers is 0.20-0.26 lb/MMBtu.[32] When combined with OFA, the estimated NO_X control range on is 0.18-0.24 lb/MMBtu.[33] LNB systems are technically feasible for the control of NO_x from SN-01.

6.3.2 POST COMBUSTION CONTROLS

6.3.2.1 SELECTIVE CATALYTIC REDUCTION

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The estimated NO_X control for SCR on coal fired boilers is 80-90%, and is consistent with vendor estimates of 0.067 lb/MMBtu at SN-01, resulting in an 80% control efficiency.[34] Control efficiencies of 80-90% depend on the design of the boiler as well as the starting baseline emissions. The vendor was able to provide an estimate of control as an outlet emission level of 0.067 lb/MMBtu, a low emission level. A 90% percent reduction would result in an outlet emission rate of 0.03 lb/MMBtu and has not been guaranteed by a vendor. This control is a technically feasible option for the control of NO_X from SN-01.

6.3.2.2 SELECTIVE NON-CATALYTIC REDUCTION

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions. The estimated NO_X control range for SNCR for coal fired boilers is 0.18-0.27 lb/MMBtu.[35] This control is a technically feasible option for the control of NO_X from SN-01.

---

[32] "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." Utility Boiler section. July 1994.

[33] Ibid.

[34] Ibid.

[35] Ibid.

6.4 Rank of Technically Feasible NO_X Control Options by Effectiveness

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section for SN-01.

Table 6-2. Control Effectiveness of Technically Feasible NO_X Control Technologies

Control Technology	Estimated Controlled Level for SN-01 (lb/MMBtu) [36]
SCR	0.067
LNB/OFA + SNCR	0.18-0.23 [37]
LNB/OFA	0.18-0.24
SNCR	0.18-0.27
FGR	0.23-0.29
LNB	0.20-0.26
OFA	0.28-0.29

With the exception of the control level for SCR, the control levels in Table 6-2 are presented as ranges. This is due to the fact that the specific level of control that is achievable for SN-01 based on the application of the controls listed in Table 6-2 is unknown. Based on several discussions between AEP Flint Creek and the Babcock and Wilcox Company, it is believed that combustion controls such as LNB in combination with OFA will achieve a NO_X level of approximately 0.23 lb/MMBtu for SN-01. EPA established presumptive SO_2 and NO_X controls for coal-fired EGUs in the BART rule. For dry-bottom wall-fired EGUs, the presumptive NO_X limit is 0.23 lb/MMBtu.[38] The presumptive BART emission rate was modeled for this source by CENRAP. Although 0.23 lb/MMBtu is the presumptive limit for a unit like SN-01, the presumptive limit was not automatically assumed the floor for combustion control on SN-01. Rather, experience with similar boilers and vendor discussions have led the selection of this emission level. Current NO_X emissions from SN-01 are approximately 0.31 lb/MMBtu. Further, it is believed that SCR will achieve a NO_X level of approximately 0.067 lb/MMBtu and LNB/OFA + SNCR will achieve a level of 0.2 lb/MMBtu or 10-20% better control than from LNB/OFA alone. Vendor estimates for LNB/OFA + SNCR were not available at the time of this analysis, and obtaining vendor estimates would add significantly to the timing of this analysis submittal.

6.5 Evaluation of Impacts for Feasible NO_X Controls

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

---

[36] Ibid.

[37] "Preferred and Alternative Methods for Estimating Air Emissions from Boilers." Volume II: Chapter 2. January 2001.

[38] Ibid.

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.5.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB/OFA, LNB/OFA + SNCR and SCR were estimated for the cost analysis.

Control Costs

The capital and operating costs of the controls that were used in the cost effectiveness calculations were estimated based on vendor estimates and published calculation methods. The EPA Air Pollution Control Cost Manual was followed to the extent possible and was supplemented with vendor and site-specific information where available. The capital costs were annualized over a 30-year period for LNB/OFA, over a 30-year period for SCR, and over a 20-year period for SNCR, and then added to the annual operating costs to obtain the total annualized costs. All predicted costs were de-escalated to a current (2013) basis assuming three (3) percent per year. The details of the capital and operating cost estimates are provided in Appendix B of this report.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rate is the average rate as reported by AEP in the 2001-2003 air emission inventories. The controlled annual emission rate is based on the lb/MMBtu level believed to be achievable from the control technology multiplied by the baseline heat input to the boiler in MMBtu/yr. The baseline heat input is based on the 2001-2003 average daily heat input for SN-01 as determined from the EPA's Clean Air Markets Database (CAMD), divided by 24 hours in a day times an estimated 7,752 hours per year, the average number of operating hours from 2001-2003.

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analyses was also performed to show the incremental increase in costs between SCR and an LNB/OFA system, as well as between LNB/OFA + SNCR and LNB/OFA. The costs effectiveness analysis is summarized in Table 6-3.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of

NO_X removed based on the use of combustion control technology.[39] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[40]

Table 6-3 indicates that the cost effectiveness of LNB/OFA at a NO_X rate of 0.23 lb/MMBtu is $1,762 per ton of NO_X removed. Table 6-3 also indicates that the costs for LNB/OFA/SNCR for SN-01 is approximately $3,100 per ton of NO_X removed and SCR for SN-01 is more than $3,500 per ton of NO_X removed. Additionally, the incremental cost of the LNB/OFA/SNCR over the LNB/OFA system is greater than $5,200 per ton of NO_X removed for SN-01. The incremental cost of SCR over the LNB/OFA system is greater than $4,000 per ton of NO_X removed for SN-01.

The cost effectiveness in dollars per deciview of visibility improvement attributable to the each NO_X control technology was also determined. Additional details on the visibility improvement analysis are provided below. The cost of LNB/OFA is approximately $233 million/dv across the Class I areas, as seen in Table 6-4. The cost of LNB/OFA plus SNCR is approximately $506 million/dv across the Class I areas, as seen in Table 6-5. Table 6-6 shows that control of NO_X from SCR results in a cost of approximately $737 million/dv across the Class I areas. So a review of cost effectiveness on a dollars per deciview basis reveals that both post-combustion control options are prohibitively expensive relative to the LNB/OFA control option.

[39] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule." CFR Vol. 77, No. 128. Wednesday, July 6, 2005, Rules and Regulations. Pages 39134-39135.

[40] Ibid.

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[4]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost (v. LNB/OFA)
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
LNB/OFA[1]	5,120.27	0.23	37,344,783	4294.65	825.62	16,000,000	1,289,382	240,000	132,364	1,454,621	1,762	-
LNB/OFA/SNCR[2]	5,120.27	0.20	37,344,783	3771.82	1348.45	23,124,235	1,961,860	240,000	2,183,048	4,177,782	3,098	5,209
SCR[3]	5,120.27	0.07	37,344,783	1251.05	3869.22	121,440,000	9,786,413	1,560,000	3,700,000	13,769,599	3,559	4,046

[1] LNB Cost information: Please refer to Appendix B.

[2] SNCR Cost information: Please refer to Appendix B.

[3] SCR Cost information: Please refer to Appendix B.

[4] Baseline heat input was determined from CAMD, 2001-2003, average daily heat inputs times the average number of operating hours from 2001-2003 divided by 24 hours in a day.

TABLE 6-4. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA

Class I Area	Baseline 98th Percentile Δdv	LNB/OFA Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual LNB/OFA Cost	$/dv
Caney Creek	0.963	0.849	0.114	1,454,621	$ 12,759,831
Hercules-Glades	0.657	0.633	0.024	1,454,621	$ 60,609,198
Mingo	0.631	0.617	0.014	1,454,621	$ 103,901,483
Upper Buffalo	0.965	0.939	0.026	1,454,621	$ 55,946,952

TABLE 6-5. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING LNB/OFA PLUS SNCR

Class I Area	Baseline 98th Percentile Δdv	LNB/OFA/SNCR 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual LNB/OFA + SNCR Cost	$/dv
Caney Creek	0.963	0.849	0.114	4,177,782	$ 36,647,214
Hercules-Glades	0.657	0.623	0.034	4,177,782	$ 122,875,952
Mingo	0.631	0.612	0.019	4,177,782	$ 219,883,283
Upper Buffalo	0.965	0.932	0.033	4,177,782	$ 126,599,466

TABLE 6-6. DOLLAR PER DECIVIEW COST EFFECTIVENESS FOR SN-01 NO_X CONTROL USING SCR

Class I Area	Baseline 98th Percentile Δdv	SCR Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Total Annual SCR Cost	$/dv
Caney Creek	0.963	0.718	0.245	13,769,599	$ 56,202,446
Hercules-Glades	0.657	0.573	0.084	13,769,599	$ 163,923,800
Mingo	0.631	0.588	0.043	13,769,599	$ 320,223,238
Upper Buffalo	0.965	0.895	0.07	13,769,599	$ 196,708,560

6.5.2 ENERGY IMPACTS & NON-AIR IMPACTS

SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_x, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

6.5.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 does not impact the annualized capital costs of potential controls because the useful life of the boiler is anticipated to be at least as long as the capital cost recovery period, which is 30 years for LNB/OFA and SCR and 20 years for SNCR.

6.6 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with LNB/OFA, LNB/OFA/SNCR and SCR systems. Section 4 of this report documented the existing visibility impairment attributable to SN-01. In order to assess the visibility improvement associated with LNB/OFA, SCR and SNCR systems, the NO_X emission rates associated with both LNB and SCR systems were modeled using CALPUFF. The controlled emission level associated with SCR systems is 0.067 lb/MMBtu for SN-01. The controlled emission level associated with the LNB/OFA system is 0.23 lb/MMBtu, and for LNB/OFA/SNCR is 0.21 lb/MMBtu. These levels were multiplied by the maximum heat input to derive hourly the hourly emission rates used in the modeling.

Tables 6-7 through 6-9 summarize the NO_X emission rates that were modeled to reflect the LNB/OFA SCR and LNB/OFA/SNCR systems, respectively. The emission rates for the other pollutants shown in Tables 6-7 through 6-9 are the same as in the baseline modeling.

TABLE 6-7. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	1,454.5	65.1	50.1	15.1	1.9

TABLE 6-8. SUMMARY OF EMISSION RATES MODELED TO REFLECT SCR FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	423.7	65.1	50.1	15.1	1.9

TABLE 6-9. SUMMARY OF EMISSION RATES MODELED TO REFLECT LNB/OFA + SNCR FOR NO_X CONTROL

SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)
4,728.4	3.1	1,277.74	65.1	50.1	15.1	1.9

Table 6-10 provides a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 in all affected Class I areas, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv.

TABLE 6-10. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEM ON SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv	Maximum Impact (Δdv)	98% Impact (Δdv)	# Days > 0.5 Δdv
Existing Emission Rate	1.318	0.963	48	2.426	0.965	63	2.103	0.657	47	1.488	0.631	20
LNB/OFA	1.232	0.849	39	2.130	0.939	56	1.938	0.633	43	1.361	0.617	17
Post Control Improvement	*0.086*	*0.114*	*9*	*0.296*	*0.026*	*7*	*0.165*	*0.024*	*4*	*0.127*	*0.014*	*3*
SCR	0.986	0.718	22	1.569	0.895	41	1.589	0.573	33	1.099	0.588	14
Improvement over LNB/OFA	*0.246*	*0.131*	*17*	*0.561*	*0.044*	*15*	*0.349*	*0.060*	*10*	*0.262*	*0.029*	*3*
LNB/OFA+ SNCR	1.201	0.849	36	2.022	0.932	54	1.878	0.623	42	1.316	0.612	17
Improvement over LNB/OFA	*0.031*	*0.000*	*3*	*0.108*	*0.007*	*2*	*0.06*	*0.010*	*1*	*0.045*	*0.005*	*0*

Note: The visibility improvement shown in the table has been calculated from baseline and controlled impacts that include more decimal places than what is shown in the table. Due to rounding of the baseline and controlled impacts shown in the table, the visibility improvement calculated from the baseline and controlled impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

The operation of an LNB/OFA system results in an estimated 0.01 to 0.11 Δdv improvement (2 to 12 percent) (98th percentile basis) of visibility impairment attributable to SN-01 at the modeled Class I areas. Further, the operation of SCR systems results in an estimated 0.02 to 0.13 Δdv incremental improvement over LNB/OFA alone, while LNB/OFA + SNCR results in an estimated 0 to 0.01 Δdv incremental improvement over LNB/OFA alone.

6.7 Proposed BART for NO_X

If CSAPR is upheld and implemented in Arkansas, SWEPCO will rely on CSAPR to satisfy its regional haze obligations at SN-01. If CSAPR is vacated, SWEPCO should be entitled to rely on EPA's prior determination that CAIR provides greater reductions than BART, and satisfy its obligations by continuing to comply with CAIR.

If a full evaluation of BART is required, the cost-effectiveness of the control options and the limited incremental improvement in visibility in the affected Class I areas do not justify the installation of SCR or SNCR. SWEPCO proposes a BART emission rate of 0.23 lb/MMBtu calculated as a 30-day rolling average for each boiler operating day, achievable through use of LNB/OFA. The visibility improvement attributable to SN-01 through the use of LNB/OFA ranges from 2.2% to 11.8% across the affected Class I areas. This level of improvement is achievable at a cost effectiveness of approximately $1,800 per ton of NO_X removed. Although LNB/OFA plus SNCR adds a slight visibility improvement over LNB/OFA alone, the small improvement does not justify the incremental cost of over $5,200 per ton of NO_X removed. The incremental cost for SCR at SN-01 is greater than $4,000 per ton of NO_X removed, and is an excessive cost to be considered BART. In addition, the adverse environmental impacts from the use of SCR, including an increased demand for electricity and the potential for ammonia slip, which could create haze, outweigh the limited, imperceptible improvements in visibility associated with its use at SN-01.

7. PM_{10} BART EVALUATION

EPA's Approval and Promulgation of Implementation Plans published March 12, 2012, determined that the currently installed ESP is BART for PM_{10} for SN-01. As such, no further PM_{10} analysis has been conducted.

APPENDIX A

SO_2 CONTROL COST CALCULATIONS

Capital and O&M Cost Estimates

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	NIDS Cost Estimate Based on EPA's Control Cost Manual	WFGD Cost Estimate Based on EPA's Control Cost Manual	*FOR COMPARISON* NIDS Cost Estimate Based on Engineering Study [b]	*FOR COMPARISON* WFGD Cost Estimate Based on Previous Project [b]
CAPITAL COSTS					
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment Cost (EC)	--	$176,899,430 [d]	$220,921,269 [e]	$176,899,430 [d]	$220,921,269 [e]
Other Purchases					
Boiler Modifications	NA	NA	NA	$985,989	$985,989 [s]
Existing Conditions	NA	NA	NA	$1,259,054 [f]	$1,608,778 [f]
CEMS	NA	NA	NA	$0 [o]	$0 [o]
Rail Improvements	NA	NA	NA	$3,141,629	$10,000,000
Sales Tax	3% of EC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Freight	5% of EC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Purchased Equipment Costs (PEC)		***$176,899,430***	***$220,921,269***	***$182,286,102***	***$233,516,035***
Direct Installation Costs					
Foundations and supports	6% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Handling and erection	40% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Electrical	1% of PEC [c]	$1,768,994	$2,209,213	$27,246,367	$18,538,032
Piping	5% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Insulation for ductwork	3% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Painting	1% of PEC [c]	$0 [k]	$0 [k]	$0 [k]	$0 [k]
Other Installation Costs	NA	NA	NA	$14,448,208 [l]	$26,661,044 [l]
Direct Installation Costs (DIC)		***$1,768,994***	***$2,209,213***	***$41,694,575***	***$45,199,076***
Other Direct Costs					
Site Preparation Costs (SPC)	--	$19,026,474	$19,026,474	$19,026,474	$19,026,474
Buildings Costs (BC)	--	$22,128,325 [p]	$54,947,952 [p]	$22,128,325 [p]	$54,947,952 [p]
Landfill Construction	--	$0 [i]	$0 [i]	$0 [i]	$0 [i]
Other Direct Costs (ODC)		***$41,154,799***	***$73,974,426***	***$41,154,799***	***$73,974,426***
Total Direct Capital Costs (DC = PEC + DIC + ODC)		***$219,823,223***	***$297,104,907***	***$265,135,476***	***$352,689,537***
Indirect Capital Costs					
Engineering	10% of PEC [c]	$17,689,943	$22,092,127		
Construction and field expenses	10% of PEC [c]	$17,689,943	$22,092,127		
Contractor fees	10% of PEC [c]	$17,689,943	$22,092,127	$77,976,320 [m]	$86,453,748 [m]
Start-up	1% of PEC [c]	$1,768,994	$2,209,213		
Performance test	1% of PEC [c]	$1,768,994	$2,209,213		
Contingency	3% of PEC [c]	$5,306,983	$6,627,638	$0 [q]	$0 [q]
Allocations	NA	NA	NA	$0 [r]	$0 [r]
AFUDC	Assumed zero (0)	$0	$0	$0 [r]	$0 [r]
Total Indirect Capital Costs (IC)		***$61,914,801***	***$77,322,444***	***$77,976,320***	***$86,453,748***
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		***$281,738,024***	***$374,427,351***	***$343,111,796***	***$439,143,286***
OPERATING COSTS					
Direct Operating Costs					
Fixed O&M Costs (Labor and Materials)					
Operating Labor ($14.24/hour) [n]	8 hr/shift, 3 shifts/day [c]	$124,742	$124,742	$884,000	$1,060,800
Operating Labor Supervision	15% of op. labor [c]	$18,711	$18,711		
Maintenance Labor ($14.24/hour) [n]	2 hr/shift, 3 shifts/day [c]	$31,186	$31,186	$1,331,100	$1,467,950
Maintenance materials	100% of maint. labor [c]	$31,186	$31,186	$1,997,500	$2,201,500
Fixed O&M Costs		***$205,825***	***$205,825***	***$4,212,600***	***$4,730,250***
Other Direct Operating Costs (e.g., utilities)					
Electricity ($0.05588/kW) [g,h]	--	$4,678,363	$8,966,862	$4,678,363	$8,966,862
Sorbent [g]	--	$2,563,783	$828,809	$2,563,783	$828,809
Water	--	$453,050	$992,500	$453,050	$992,500
Waste Disposal	--	$1,300,698	$1,231,419	$1,300,698	$1,231,419
Bag and Cage Replacement	--	$483,000	$483,000	$483,000	$483,000
Other Direct Operating Costs		***$9,478,894***	***$12,502,590***	***$9,478,894***	***$12,502,590***
Total Direct Operating Costs (DOC)		***$9,684,719***	***$12,708,415***	***$13,691,494***	***$17,232,840***
Indirect Operating Costs					
Overhead	60% of O&M [c]	$0 [j]	$0 [j]	NA	NA
Property tax	1% of TCI [c]	$2,394,773 [j]	$3,182,632 [j]	NA	NA
Insurance	1% of TCI [c]	$29,582 [j]	$39,315 [j]	NA	NA
Administration	2% of TCI [c]	$5,634,760	$7,488,547	NA	NA
Capital Recovery (30 years, 7 %)	0.0806 of TCI	$22,704,254	$30,173,754	$27,650,146	$35,388,978
Total Indirect Operating Costs (IOC)		***$30,763,370***	***$40,884,248***	***$27,650,146***	***$35,388,978***
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		***$40,448,089***	***$53,592,663***	***$41,341,640***	***$52,621,818***

[a] Default estimates are based on information published in the EPA Cost Control Manual, Sixth Edition. These estimates are used for all cost calculations except as noted.

[b] The NIDS option estimate is based on a site-specific engineering study. The estimate for the WFGD option was generated from the actual costs for the Conesville Unit 4 WFGD project (prorated). No attempt was made to make the estimate site specific and is deemed to be a Class 5 estimate per AACE International standards. All costs are in 2016 dollars.

[c] EPA Cost Control Manual, Sixth Edition, Table 2-8 and Table 2.9.

[d] Includes lime receiving, handling, and storage equipment, DFGD (J Duct), ID fan, flue gas duct, fabric filter, fly ash / byproduct handling and storage equipment.

[e] Includes reagent receiving equipment, JBR and WFGD system, ID fan, flue gas duct, fabric filter, and stack.

[f] "Existing conditions" includes site specific activities necessary for the construction of the project such as removal of existing equipment and asbestos and lead paint remediation and work at tie-in points of the new e

[g] Based on the average annual operating hours from the 2001 to 2003 baseline period: 7752

[h] Based on engineering estimates, the auxiliary power demand is 10,800 kW for NIDS and 20,700 kW for a WFGD system.

[i] No landfill construction costs are included.

[j] In the OK FIP TSD, EPA used alternative (compared to the Control Cost Manual) estimates for these costs, i.e., zero for Overhead, 0.85 % of TCI for Property tax, and 0.0105 % of TCI for Insurance. These same estimates are used here for consistency.

[k] The estimated equipment cost (EC) includes sales tax, freight, foundations & support, handling & erection, piping, insulation, and painting.

[l] Includes utility racks, plant and instrument air, various water supplies, sewers, and plant security and communications (i.e., phone and PA systems for employee safety).

[m] Includes construction indirects, outside professional services (e.g., start-up technical support, specialty testing, geophysical engineering services, and surveying), conceptual and detailed design engineering, project management and controls, AEP services (owners estimated involvement in project management, engineering, project controls, procurement, and construction and start-up supervision), and, for the WFGD option only, startup management and plant labor (these costs for the NIDS option are included in other categories).

[n] Labor rates based on engineering estimates.

[o] New/revised CEMS and related equipment, including buildings, will be required for each control option, but costs are not included for this assessment.

[p] Included buildings: Process island building, lime (sorbent) building, byproduct exhauster building, control room, and warehouse.

[q] AEP's projects team develops an elaborate risk analysis to estimate contingency and has refined its approach with each project. For example, for the recent Conesville project, the estimated contingency was $42MM and actual costs were just less than $35MM. However, for the purposes of this assessment, all contingency costs are set equal to zero.

[r] Allocations and AFUDC costs are excluded, i.e., assumed to be zero (0), for the purposes of this assessment.

[s] It is expected that more extensive boiler modifications would be needed for the WFGD option than the NIDS option, but costs are conservatively assumed equal to the NIDS option estimate.

APPENDIX B

NO_X CONTROL COST CALCULATIONS

LNB/OFA Capital and O&M Cost Estimate

Capital Costs		**Total Direct Capital**
Technology LNB-OFA		
Material Capital Costs[1]		
Total Capital Cost Plus Installation		$16,000,000
Annual Costs[2]		
Parameters/Costs	Equation	Unit 1
Boiler design capacity, mmBtu/hr (C) Annual operating hours, hr/yr (H)	C H = average from 2001-2003	6324 7752
Capital recovery factor	= [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Direct Annual Operating Costs $/yr Variable O&M Costs	=(0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu	$132,364
Indirect Annual Costs, $/yr 1. Fixed O&M Costs (1.5% of capital cost) 2. Annualized capital cost	 = 0.015 x TCI = Equipment CRF x TCI	 $240,000 $1,289,382
Total Annual Costs ($/yr) 2017/2018 Basis		$1,661,746
Total Annual Costs ($/yr) 2013 Basis	Assume 3 % per year for de-escalating 4.5 years	$1,454,621

[1] Public Service Commission Docket 12-008-U.

[2] Annual cost calculation methods for variable costs and fixed costs from Eastern Research Group "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D.
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

SCR Capital and O&M Cost Estimate

Capital Costs		**Total Direct Capital**
Technology SCR		
Installed Capital Cost[1]		$121,440,000
Annual Costs		
Variable		
Urea[1]		$2,200,000
Catalyst replacement (per year)[1]		$1,500,000
Total Variable O&M[1]		$3,700,000
Fixed		
Operating Labor Cost[2]	$530,000	
Maintenance Labor[3]	$530,000	
Maintenance Material[1]	$500,000	
Total Fixed O&M[1]		$1,560,000
Capital recovery factor	= [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Annualized capital cost	= Equipment CRF x TCI	$9,786,413
Total Annual Costs ($/yr) 2016 Basis		$15,046,413
Total Annual Costs ($/yr) 2013 Basis	Assume 3 % per year for de-escalating 3 years	$13,769,599

[1] All capital and O&M cost estimates provided by AEP are based on engineering estimates. The engineering estimates were informed by AEP's experience with SCR installations at other plants owned by AEP

[2] Annual estimates provided by AEP based on 1 person per shift for 5 shifts.

[3] Annual estimates provided by AEP based on 1 person per shift for 5 shifts.

Selective Non-Catalytic Reduction Capital and O&M Cost Estimate[1]

Capital Costs		
Technology SNCR		
Parameters/Costs	Equation	Unit 1
Boiler design capacity, mmBtu/hr (Q_B)	Q_B	6324
Total operating time (t_{op}, hrs/yr)	$t_{op} = CF_{total} \times 8760$ hrs/yr	7752
Total Capacity Factor (CF_{total})	$CF_{total} = CF_{plant} \times CF_{SNCR}$	0.92
Plant Capacity Factor (CF_{plant})[2]		0.92
SNCR Capacity Factor (CF_{SCNR})[3]	$CF_{SNCR} = t_{SNCR}/365$	1
Assumed NOx removal efficiency (η_{NOx})[4]		35%
Uncontrolled NOx rate (NOx_{in}, lb/MMBtu)[5]		0.33
Electricity Cost ($Cost_{elect}$, $/kwh)[6]		$0.05
Water Cost ($Cost_{water}$, $/gal)[7]		$0.00362
Coal Cost ($Cost_{coal}$, $/MMBtu)[8]		$2.50
Coal HHV (Btu/lb)[9]		9,000
Cost of Ash Disposal (C_{ash}, $/ton)[10]		$9.0
Capital recovery factor (CRF)	CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 20-yr life, 7% interest	0.09
Cost Index[11] a. 2011 Cost Index b. 1998 Cost Index	 585 389.5	
Capital Costs		
Direct Capital Cost (A)	DC ($) = ($950/MMBtu) × Q_B × ((2375 MMBtu/hr/Q_B)^0.577) × (0.66 + 0.85 η_{NOx}) × (CI_{2011}/CI_{1998})	$5,007,199
Indirect Installation Costs ($)		
General Facilities	0.05 × A	$250,360
Engineering and Home Office Fees	0.10 × A	$500,720
Process Contingency	0.05 × A	$250,360
Total Indirect Installation Costs (B)	= General Facilities Cost + Engineering and Home Office Fees + Process Contingency	$1,001,440
Other Installation Costs ($)		
Project Contingency (C)	C = 0.15 × (A + B)	$901,296
Total Plant Cost (D)	D = A + B + C	$6,909,934
Allowance for Funds During Construction (E)	E = 0 (Assumed for SNCR)	$0
Royalty Allowance (F)	F = 0 (Assumed for SNCR)	$0
Preproduction Cost (G)	G = 0.02 × (D + E)	$138,199
Inventory Capital (H)[12]	H = $Vol_{reagent}$ (gal) × $Cost_{reagent}$ ($/gal)	$76,102
$Cost_{reag}$, 50% Urea solution ($/gal)[13]		1.54
Volume of Reagent Tank ($Vol_{reagent}$ (gal))	$Vol_{reagent}$ (gal) = q_{sol} x days of reagent supply × 24 hr/day	49,417
Urea solution volumetric flow rate (q_{sol}, gal/hr)[14]	$q_{sol} = (m_{sol}$ x 7.481 gal/ft^3)/$\rho_{reagent}$	147.07
Mass flow rate of urea solution (m_{sol}, lb/hr)[15]	$m_{sol} = m_{reagent}/C_{ureasol}$	1,395.84
Mass flow rate of reagent ($m_{reagent}$, lb/hr)[16]	$m_{reagent} = (NOx_{in}$ x Q_B x η_{NOx} × NSR x $M_{reagent})/(M_{NOx}$ x $SR_T)$	697.92
Normalized Stoichiometric Ratio (NSR)	NSR = ([2 × NOx_{in} + 0.7] × η_{NOx})/NOx_{in}	1.43
Initial Catalyst and Chemicals (I)	I = 0 (Assumed for SNCR due to no catalyst)	$0
Total Capital Investment (TCI) (Capital Cost)	**TCI = D + E + F + G + H + I**	**$7,124,235**
Annual Costs ($)		
Annual Maintenance Cost (J)	J = 0.015 × TCI	$106,864
Annual Reagent Cost (K)	K = q_{sol} × $Cost_{reag}$ × t_{op}	$1,755,781
Annual Electricity Cost (L)	L = P × $Cost_{elect}$ × t_{op}	$58,064
Power (P, kW)	P = (0.47 × NOx_{in} × NSR × Q_B)/9.5	149.80
Annual Water Cost (M)	M = q_{water} × $Cost_{water}$ × t_{op}	$18,775
Water flowrate for SNCR system (q_{water}, gal/hr)[17]	$q_{water} = (m_{sol}/\rho_{water})$ × [($C_{ureasolstored}/C_{ureasolinj}$) - 1]	669.06
Annual ΔCoal Cost (N)	N = ΔCoal × $Cost_{coal}$ × t_{op}	$109,558
Additional coal required (ΔCoal, MMBtu/hr)[18]	ΔCoal = (Hv × $m_{reagent}$ × [(1/$C_{ureasolinj}$) - 1])/10^6 Btu/MMBtu	5.65
Annual ΔAsh Cost (O)	O = (ΔAsh × $Cost_{ash}$ × t_{op})/2000 lb/ton	$1,643
Additional ash generated (ΔAsh , lb/hr)[19]	ΔAsh = (ΔCoal × ashproduct × 10^6 Btu/MMBtu)/HHV	47.11
Direct Annual Costs (DAC)/Variable O&M	**DAC = J + K + L + M + N + O**	**$2,050,684**
Indirect Annual Costs (IDAC)/Annualized Capital Cost	**IDAC = CFR × TCI**	**$672,477**
Total Annualized Costs (TAC)	**TAC = DAC + IDAC**	**$2,723,162**

[1] All SNCR costing equations from EPA Air Pollution Control Cost Manual (APCCM), 6th Edition (January 2002)

[2] Plant capacity factor from plant data

[3] t_{SCNR} assumed to be 365 days

[4] η_{NOx} (NOx removal efficiency) assumed to be 33% for SNCR alone

[5] 24-hr NOx rate 46,680 lbs/day - from Clean Air Markets Database, with a heat input of 6324 MMBtu/hr

[6] Electricity cost form Arkansas Industrial Energy Clearinghouse, http://www.arkansasiec.org/newsmanager/templates/?a=71&z=1

[7] Water cost estimate from Bentonville, AR commercial rate of $0.00362/gal, http://www.bentonvillear.com/utbc_rates.html

[8] Cost of coal from Lazard's 2009 Levelized Cost of Energy Analysis (LCOE)

[9] Coal used at AEP Flint Creek originates from Powder River Basin near Gillette, WY and is considered to be subbituminous (source: http://www.aecc.com/about/generation-facilities/)
HHV for subbituminous coal ranges from 8,000 - 10,000 Btu/lb (EPA APCCM, 2002).
Using HHV of 9,000 Btu/lb

[10] Cost of ash disposal from BART Analysis for NCS Unit 1, Appendix A

[11] From Chemical Engineering Plant Cost Index (CEPCI)

[12] Cost for urea stored on site, i.e., the first fill of the reagent tanks.

[13] Five-yr average urea cost = $356.11/metric ton, from http://www.indexmundi.com/commodities/?commodity=urea&months=180
Density of 50% urea solution = 9.5 lb/gal (50% urea solution) based on EPA APCCM, 2002
Equates to $1.54/gal

[14] $\rho_{reagent} = 71.0$ lb/ft^3

[15] $C_{ureasol}$ = urea solution concentration = 50%

[16] $M_{reagent} = 60.6$ g/mol (molecular weight of urea)
$M_{NOx} = 46.01$ g/mol (molecular weight of NO_2)
SRT = 2 (ratio of equivalent moles NH_3 per mole of urea)

[17] Concentration of stored urea, $C_{ureasolstored} = 50\%$
Concentration of urea injected into SNCR system, $C_{ureasolinj} = 10\%$
From EPA APCCM, 2002

[18] Approximate heat of vaporization of water at 310°F, Hv = 900 Btu/lb From EPA APCCM, 2002

[19] Ashproduct is the fraction of ash produced as a byproduct of burning a given type of coal. Assumed ashproduct = 0.075 from EPA APCCM, 2002 for subbituminous coal.

APPENDIX C

CALMET PROTOCOL

The meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

Prepared by:

Vern Choquette ▲ Principal Consultant
Eugene Chen, PE ▲ Senior Consultant
Jeremy Townley ▲ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

January 23, 2008

Project 083701.0004

TABLE OF CONTENTS

1. INTRODUCTION 1-1
1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND 1-1
1.2 OBJECTIVE 1-2
1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS 1-2

2. CALPUFF MODEL SYSTEM 2-1
2.1 MODEL VERSIONS 2-1
2.2 MODELING DOMAIN 2-1

3. CALMET 3-1
3.1 GEOPHYSICAL DATA 3-1
3.1.1 TERRAIN DATA 3-1
3.1.2 LAND USE DATA 3-2
3.1.3 COMPILING TERRAIN AND LAND USE DATA 3-3
3.2 METEOROLOGICAL DATA 3-3
3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA 3-3
3.2.2 SURFACE METEOROLOGICAL DATA 3-4
3.2.3 UPPER AIR METEOROLOGICAL DATA 3-5
3.2.4 PRECIPITATION METEOROLOGICAL DATA 3-6
3.2.5 BUOY METEOROLOGICAL DATA 3-7
3.3 CALMET CONTROL PARAMETERS 3-8
3.3.1 VERTICAL METEOROLOGICAL PROFILE 3-8
3.3.2 INFLUENCES OF OBSERVATIONS 3-9

APPENDIX A- METEOROLOGICAL STATIONS

APPENDIX B – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 5.8)

APPENDIX C – SAMPLE CALMET CONTROL FILE (CALPUFF VERSION 6)

EPA-HQ-2018-002296

LIST OF TABLES

TABLE 1-1. BART-ELIGIBLE SOURCES 1-2

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS 1-2

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS 2-1

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN 3-9

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS A-1

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS A-5

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS A-6

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS A-14

ED_002110_00032806-00051

LIST OF FIGURES

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS 1-3

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN 2-2

FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA 3-2

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA 3-3

FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS 3-5

FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS 3-6

FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS 3-7

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS 3-8

1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

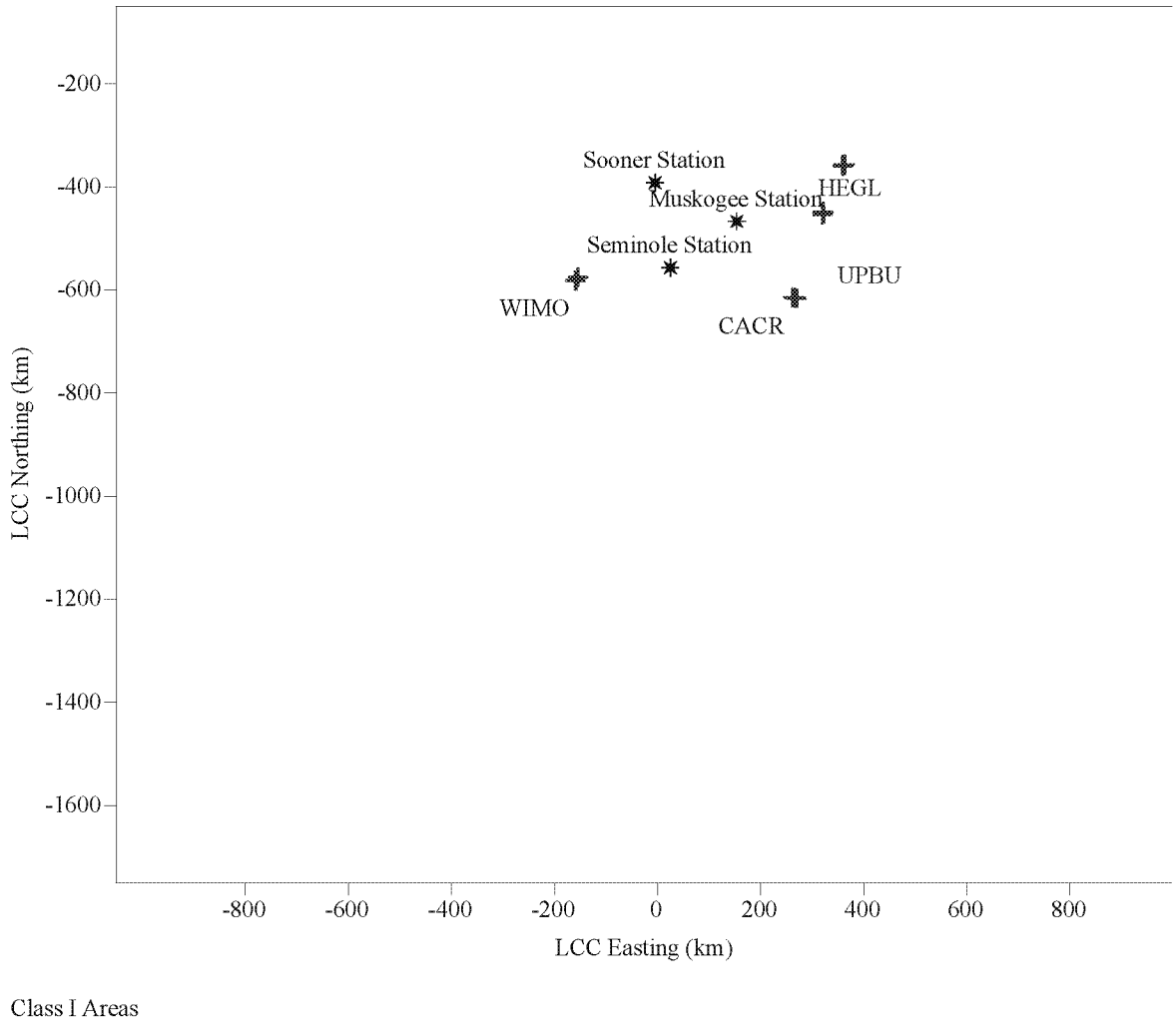
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE FROM STATION TO SURROUNDING CLASS I AREAS

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs". CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E's BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

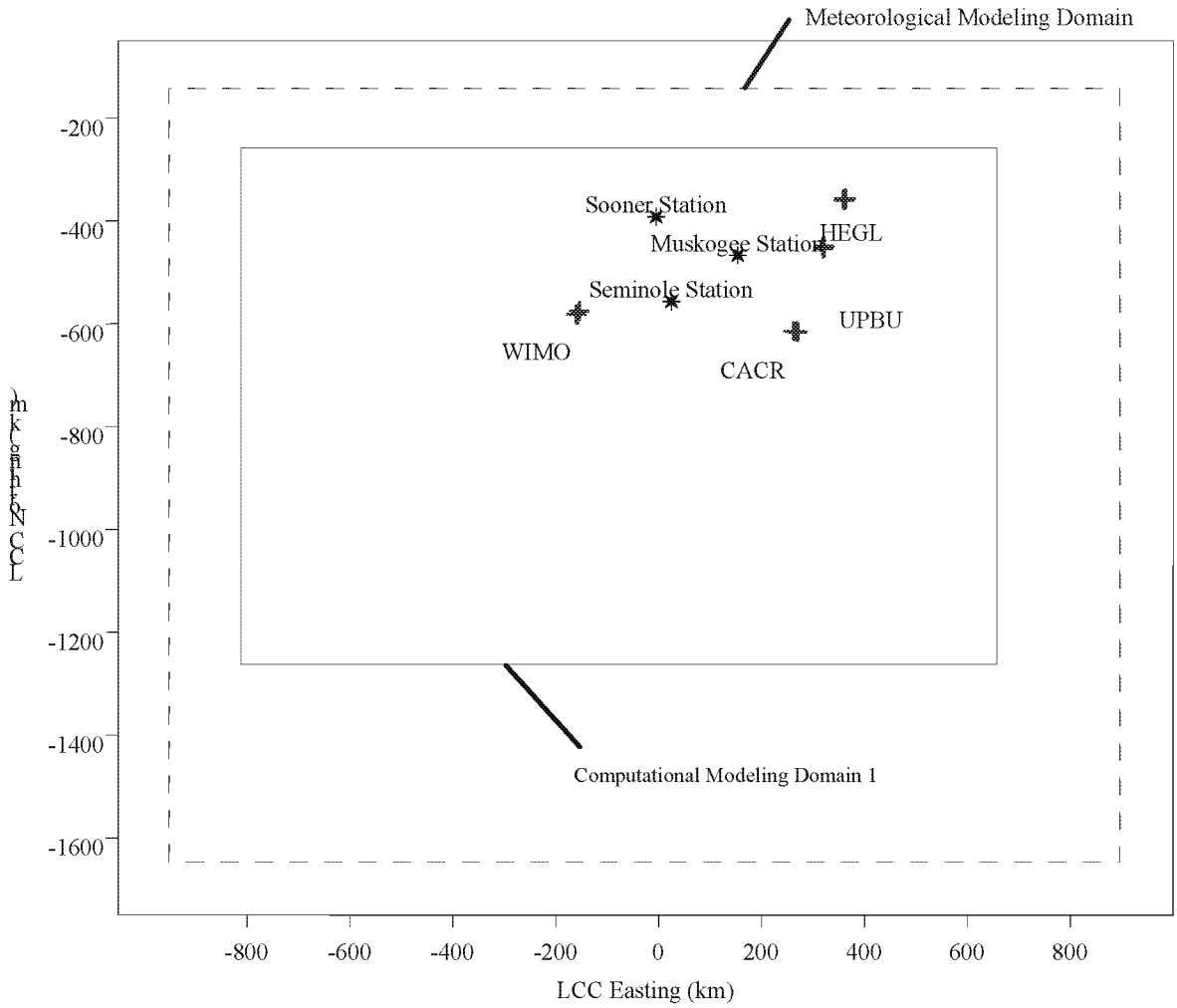
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40°N, Longitude 97°W. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 °N and Longitude 87.778°W. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



Class I Areas

3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

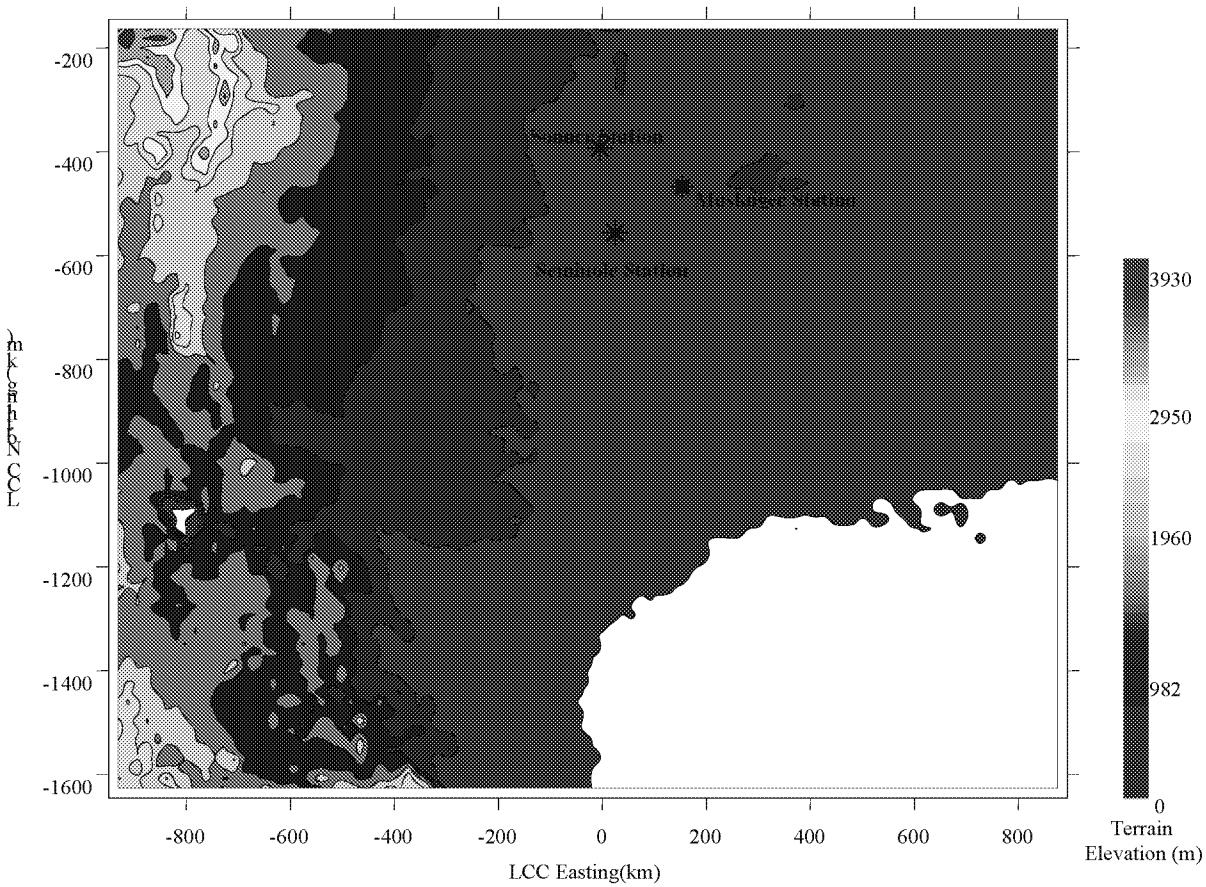
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then be processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

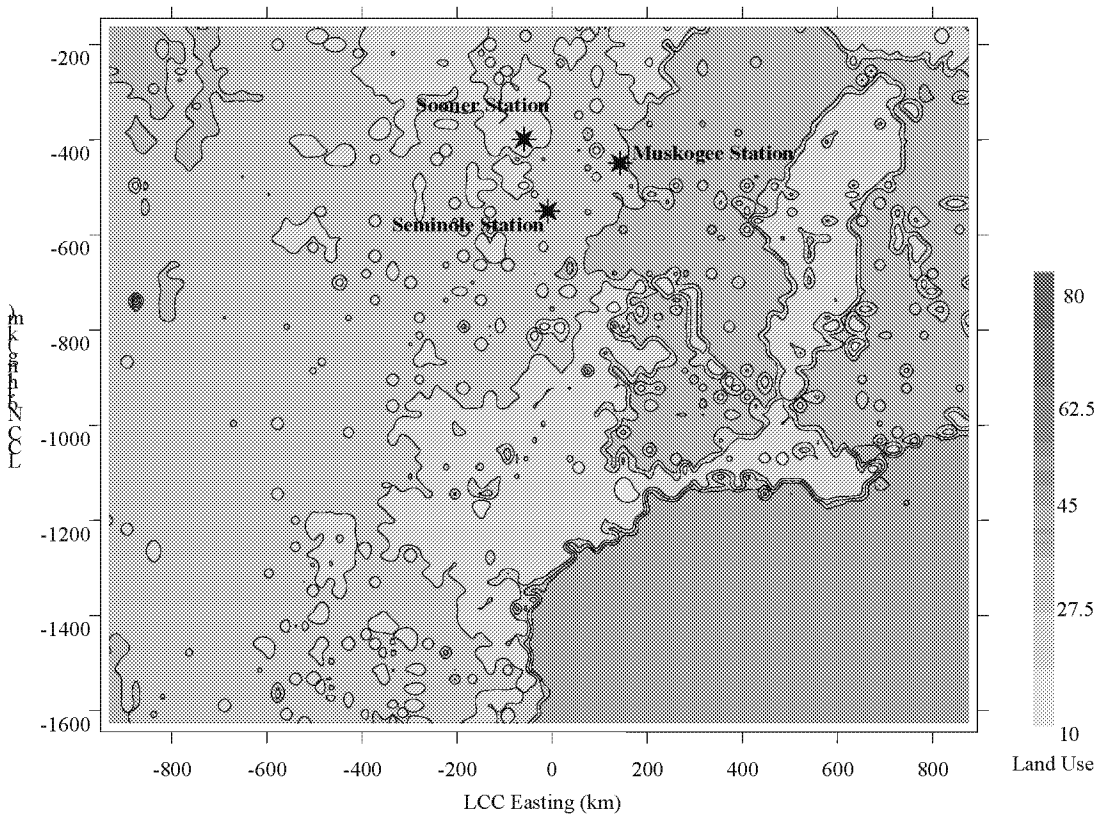
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which will generate land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is OG&E's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. TXI is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

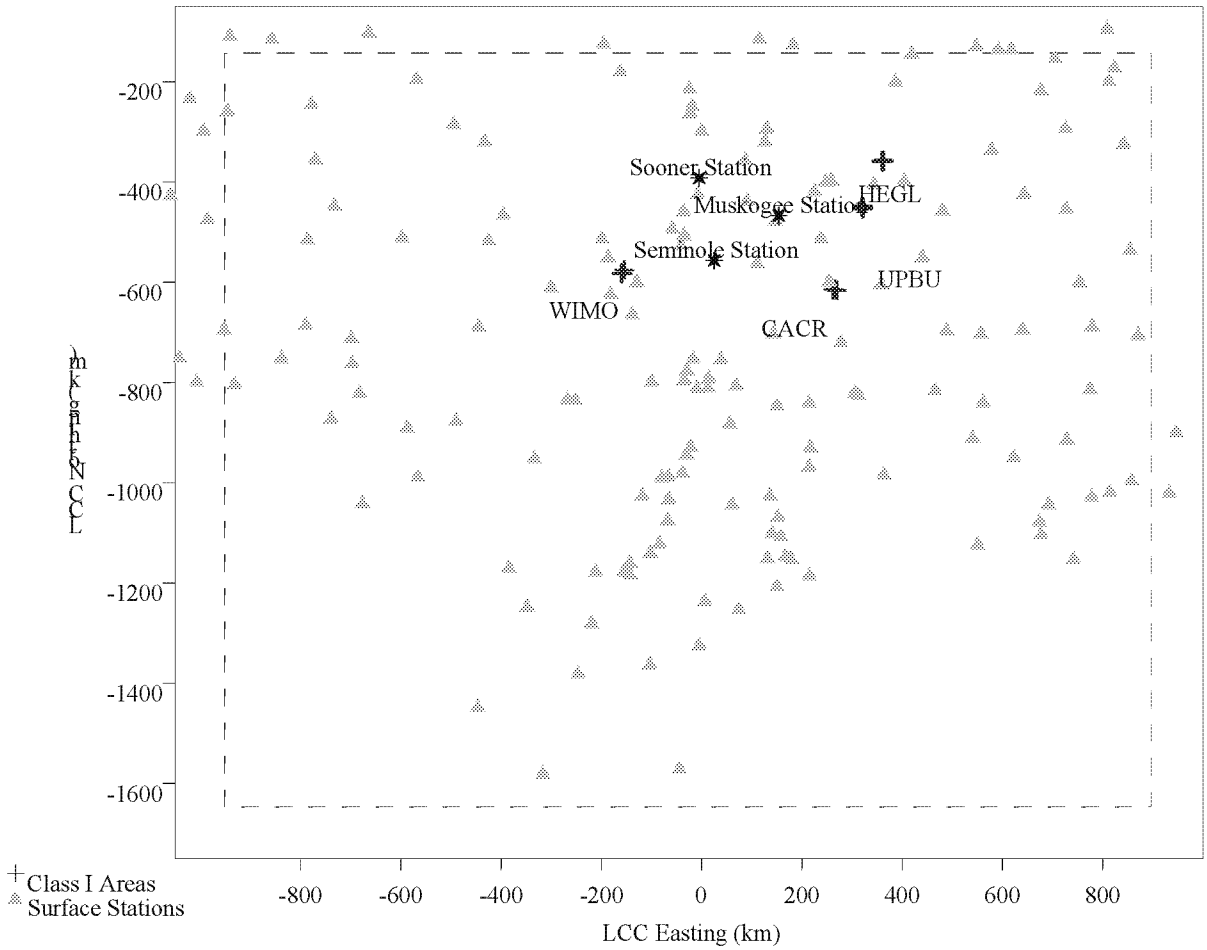
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is OG&E's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

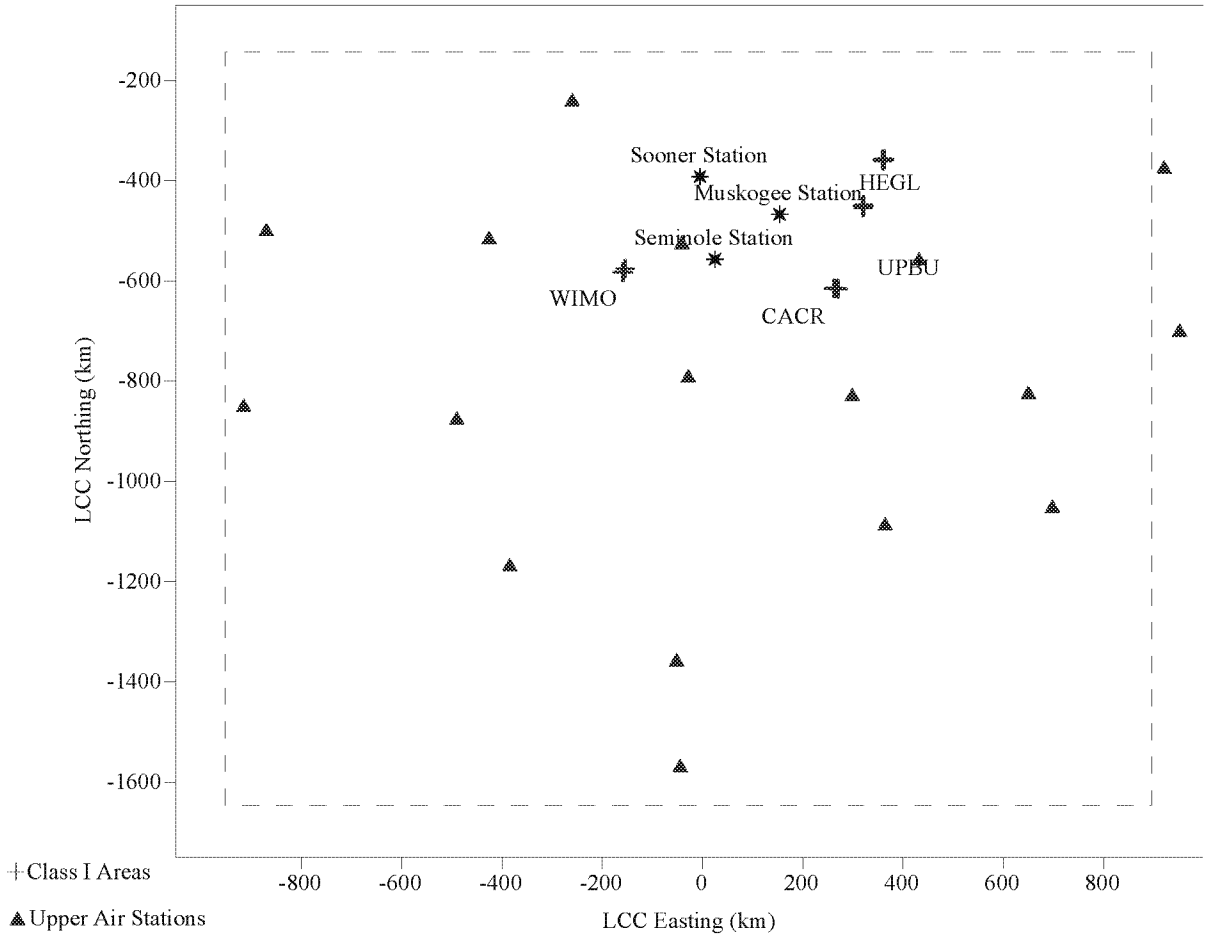
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

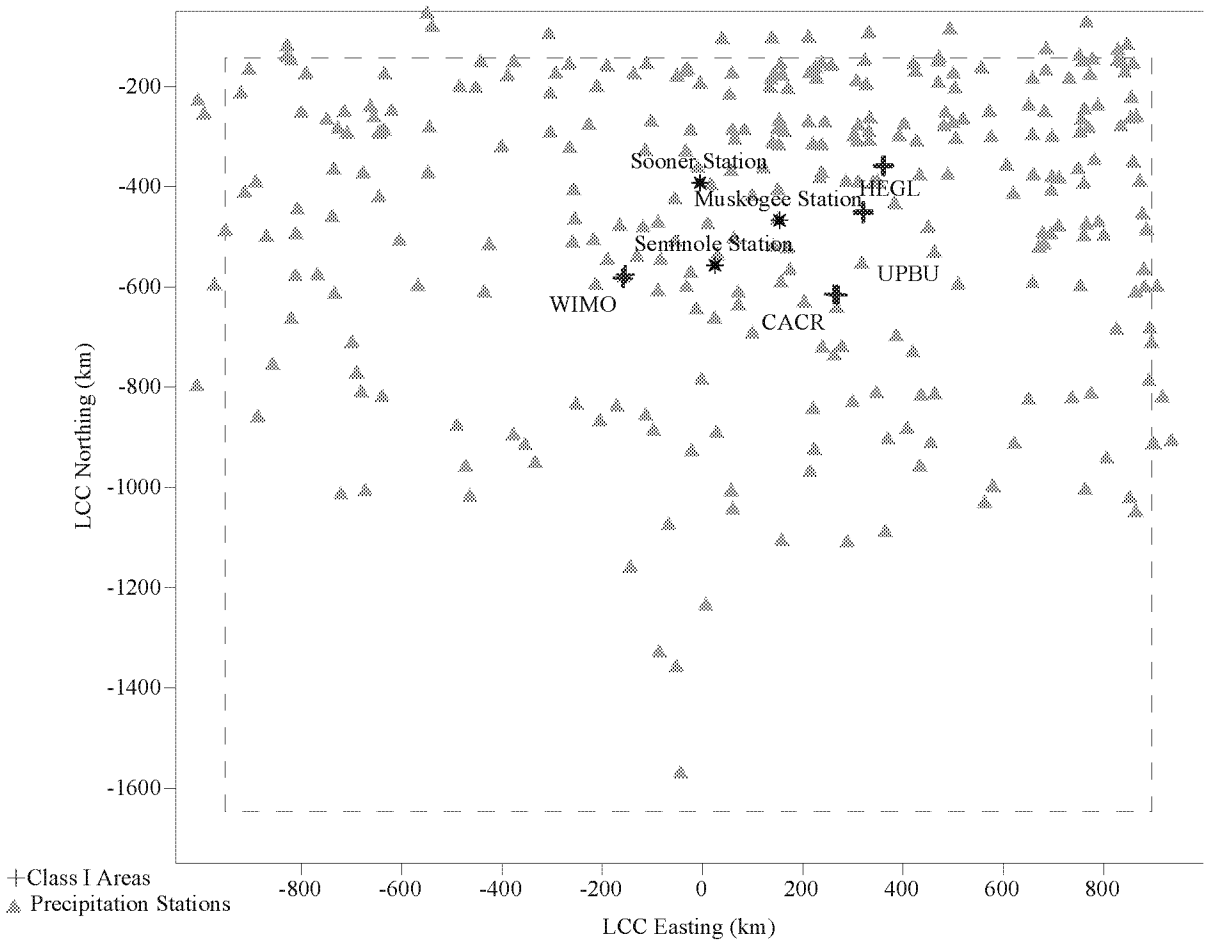
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

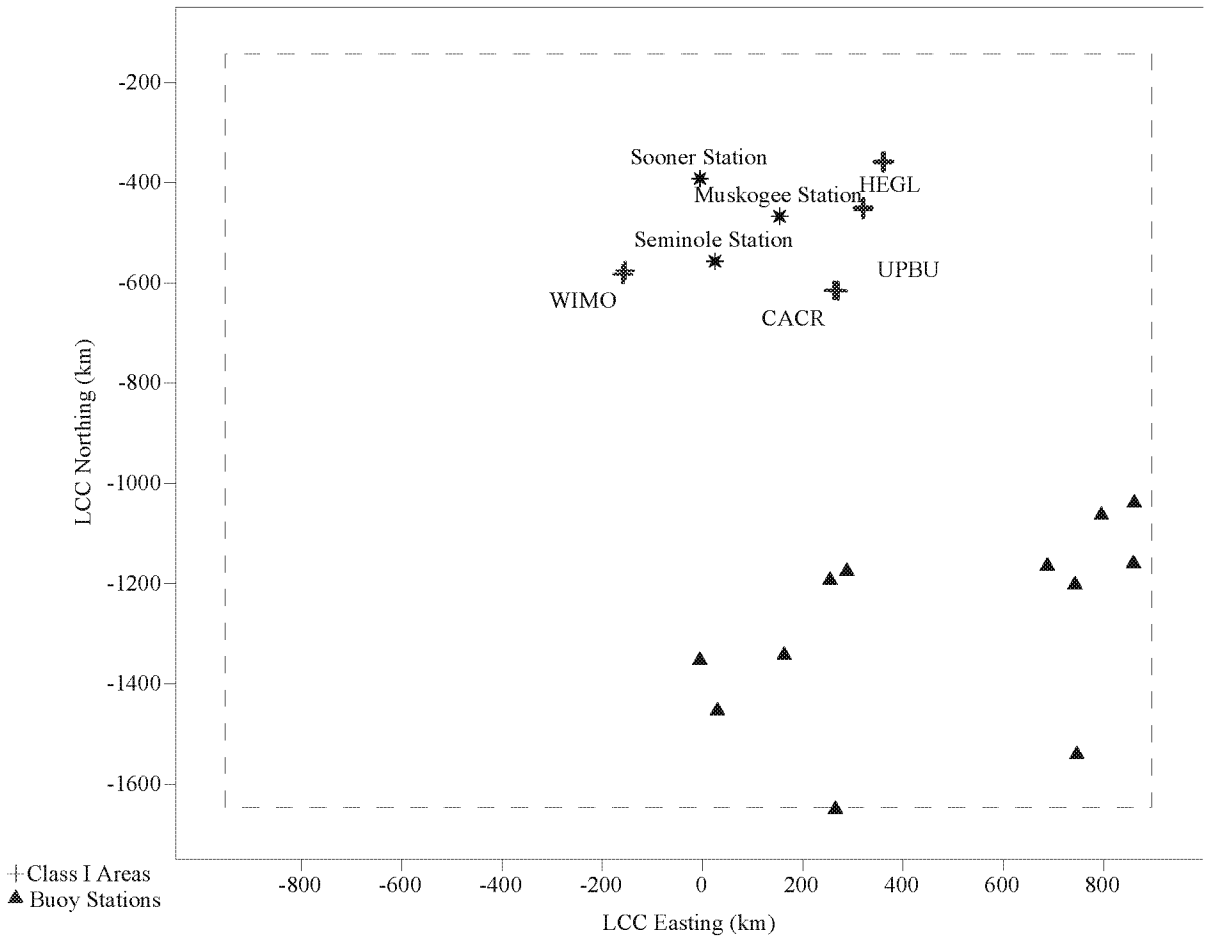
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2

wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

Message

From: Chris Kersting [chrisk@sema.org]
Sent: 9/27/2017 3:51:46 PM
To: Jonathan E. Missner [JMissner@steinmitchell.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Traylor, Patrick [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=b6d06c6b766c4b4b8bfdf6b0fea4b998-Traylor, Pa]
Subject: Re: E-Connect

Mandy -
Thanks for the call today - much appreciated. Patrick, good to connect with you by this email introduction. Would be great if we could get a slot with you for a phone conversation - if you could kindly let us know of your availability, we'll get something scheduled.
Thank you all again and we look forward to following up.
Best regards,

Chris Kersting
President and CEO, SEMA

On Sep 27, 2017, at 8:35 AM, Jonathan E. Missner <JMissner@steinmitchell.com> wrote:

> Thanks again Mandy. I copy Chris Kersting, the CEO of SEMA who will be in touch today. Best, JON
>
> ---
>
> **From:** <Gunasekara>, Mandy
> **Date:** Wednesday, September 27, 2017 at 11:30 AM
> **To:** Jonathan Missner
> **Cc:** "Traylor, Patrick"
> **Subject:** E-Connect
>
> Jonathan,
> Great chatting with you this morning. I could not find Chris's email address so please loop him in. As promised, I'm connecting you with Patrick Traylor (cc'd) who is the Deputy in OECA and will be good to touch base with.
>
> Patrick,
> Jonathan (and Chris once looped in) works for the Specialty Equipment Manufacturers Association (SEMA) and have some questions regarding related enforcement policies. They have been working closely with Congress on the RPM Act, so much of the discussion will be relative to that effort and some back-and-forth they received from OECA.
>
> I'll leave to you both to find a time to connect. Let me know if I can help.
> Best,
> Mandy
>
> **Mandy M. Gunasekara**
> Senior Policy Advisor for Office of Air and Radiation
> Office of the Administrator
> US Environmental Protection Agency

Message

From: Thaker, Rahul [rahul.thaker@ncdenr.gov]
Sent: 9/22/2017 6:06:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: hello

Hello Mandy:
It was good to see you at the AAPCA's meeting in Raleigh. Your presentation was very good. See you next time.
Rahul

Rahul P. Thaker, P.E., QEP
Environmental Engineer
Division of Air Quality, Permitting Section
North Carolina Department of Environmental Quality

919 707 8740 office/fax
rahul.thaker@ncdenr.gov

217 West Jones Street
1641 Mail Service Center
Raleigh, NC 27699-1641

Nothing Compares

Email correspondence to and from this address is subject to the North Carolina Public Records Law and may be disclosed to third parties.

Message

From: Reitter, Annabeth [Annabeth.Reitter@domtar.com]
Sent: 9/21/2017 9:26:44 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: FW: Domtar Ashdown Mill Regional Haze Matter

Hi Mandy,

I realized your email address I have been using may not be a current email address. So I am resending this email thread to an alternate email address in case you have not received. I apologize if I was not using the correct email address.

Is there any information you can share with how EPA wants to proceed on this matter? DOJ is looking for a response from us by the end of the week (Friday) on how we may be proceeding. At this point, anything you can provide would be very helpful. I know you are extremely busy and juggling many different issues. If you need more time on this one, just let me know and we can pass that on to DOJ.

Really appreciate your assistance. Hope to hear from you soon.

Thanks,

Annabeth

From: Reitter, Annabeth
Sent: Wednesday, September 20, 2017 7:51 AM
To: gunasekara.mandy@epa.gov
Cc: dominguez.alexander@epa.gov
Subject: RE: Domtar Ashdown Mill Regional Haze Matter

Hi Mandy,

I am checking-in after our discussion last week to see if you have had a chance to follow-up with folks on your end.

If you need to reach me, I am available via email or mobile phone at 715-459-9257,

I look forward to hearing from you.

Thanks,

Annabeth

From: Reitter, Annabeth
Sent: Thursday, September 14, 2017 4:49 PM
To: gunasekara.mandy@epa.gov
Cc: dominguez.alexander@epa.gov
Subject: Domtar Ashdown Mill Regional Haze Matter

Hi Mandy,

Thank you for your time this afternoon to discuss the Regional Haze solution for our Ashdown Mill. The updated CALPUFF modeling reflecting the Mill's current operations supports U.S. EPA making a determination that the Ashdown Mill is "not subject to BART". Furthermore there is no basis to impose BART requirements or further restrict the Ashdown Mill's operations when it is not impacting visibility in the nearby Class 1 areas.

A soon as possible, please let us know which approach U.S. EPA will want to take to declare the Ashdown Mill not subject to BART;

- Region 6 approval of the ADEQ SIP revision with Power Boiler 1 and Power Boiler 2 not subject to BART

  Or
- Administrator Pruitt granting the exemption under 40 CFR 51.303.

I look forward to hearing back from you as soon as practical.

Thank you for your attention to this important matter.

Annabeth

Annabeth Reitter
Corporate Manager, Environmental Regulation
T 715-886-7785 | C 715-459-9257

Domtar

Domtar
301 Point Basse Avenue
Nekoosa, WI 54457

Domtar reminds you to print responsibly. Learn more about paper as a sustainable choice at **paperbecause.com**

This email is for the exclusive use of the addressee and is subject to Domtar Confidentiality Notice.

Message

From: Stephanie Glyptis [SGlyptis@AWMA.ORG]
Sent: 10/2/2017 6:42:57 PM
To: Webb, C. Flint [C.FLINT.WEBB@leidos.com]; Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]; Cindy Fontanesi [CFontanesi@AWMA.ORG]
CC: Tracy Fedkoe [TFedkoe@AWMA.ORG]; cnelson [cnelson@mmm.com]; michele.gehring@coterie-env.com; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; jcmuffat [jcmuffat@yahoo.com]; wwehrum@hunton.com
Subject: RE: (UPDATE) RE: Climate Change Keynote Mandy

Flint,
Cindy and I have all the relevant information from Alex. We are connected with Ms. Dravis' office and will be taking it from here.

Thanks,
Stephanie

Stephanie M. Glyptis
Executive Director
Air & Waste Management Association
420 Fort Duquesne Boulevard
One Gateway Center, Third Floor
Pittsburgh, Pennsylvania 15222 USA
Phone: 412.232.3444 (x6006)
Direct: 412.904.6006
Fax: 412.232.3450
sglyptis@awma.org
www.awma.org

-----Original Message-----
From: Webb, C. Flint [mailto:C.FLINT.WEBB@leidos.com]
Sent: Monday, October 02, 2017 2:42 PM
To: dominguez.alexander@epa.gov; Cindy Fontanesi <CFontanesi@AWMA.ORG>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; cnelson <cnelson@mmm.com>; michele.gehring@coterie-env.com; Stephanie Glyptis <SGlyptis@AWMA.ORG>; Gunasekara.Mandy@epa.gov; jcmuffat <jcmuffat@yahoo.com>; wwehrum@hunton.com
Subject: RE: (UPDATE) RE: Climate Change Keynote Mandy

Thank you.
Alex, I was able to download a bio for Ms. Dravis from the web.
Please either pass on the original e-mail I sent to Mandy to Ms. Dravis or provide me with her e-mail so she has the information about the Speaker's Breakfast, the Presentation, and the schedule.

Flint Webb, P.E.
C.Flint.Webb@Leidos.com
Baltimore-Washington Chapter: Vice Chair Technical Council: Climate Change Division Vice Chair Finding Common Ground on Climate Change Mitigation and Adaptation:
General Conference Chair
South Atlantic States Section: Director
Air & Waste Management Association
Work: 571-526-7706
Cell: 703-582-8094

-----Original Message-----
From: Stephanie Glyptis [mailto:SGlyptis@AWMA.ORG]
Sent: Monday, October 02, 2017 2:04 PM
To: dominguez.alexander@epa.gov; wwehrum@hunton.com; Cindy Fontanesi; Gunasekara.Mandy@epa.gov; jcmuffat; Webb, C. F. [US-US]
Cc: Tracy Fedkoe; cnelson; michele.gehring@coterie-env.com
Subject: EXTERNAL: (UPDATE) RE: Climate Change Keynote Mandy
Importance: High

Flint et al ~

I just spoke with Alexander Dominguez from Mandy's office. They have worked within their offices, and Samantha Dravis, Associate Administrator of EPA's Office of Policy, will be stepping in to speak as the Keynote.

Ms. Dravis' Chief of Staff will be in touch with Cindy and me (Alex will be connecting us) and we'll work to get all the information updated on our end (i.e., website, promotions, final program).

Alex,
My sincerest thanks to you and Ms. Gunasekara's office for working so diligently with us on our Keynote speaker even with Mandy's schedule change. On behalf of the Association we truly appreciate EPA's support and participation.

All the best,
Stephanie

Stephanie M. Glyptis
Executive Director
Air & Waste Management Association
420 Fort Duquesne Boulevard
One Gateway Center, Third Floor
Pittsburgh, Pennsylvania 15222 USA
Phone: 412.232.3444 (x6006)
Direct: 412.904.6006
Fax: 412.232.3450
sglyptis@awma.org
www.awma.org

-----Original Message-----
From: Webb, C. Flint [mailto:C.FLINT.WEBB@leidos.com]
Sent: Monday, October 02, 2017 12:08 PM
To: Dominguez, Alexander <https://urldefense.proofpoint.com/v2/url?u=http-3A__dominguez.alexander-40epa.gov&d=DwIGaQ&c=euGZstcaTDllvimEN8b7jXrwqOf-v5A_CdpgnVfiiMM&r=I2EakDkHCz8LPL8q80bkmABpXnftzypKkbsoPJKgRJO&m=aZ5fzhDcXeY-GR2wuzl3RBQgzl1i49naGYj_zNYfaVA&s=xxvu_L88Dg57RvOFWu6K-FkkWmoE5t5qXlq_GKrRxY4&e=>
Cc: William L. Wehrum <wwehrum@hunton.com>; Cindy Fontanesi <CFontanesi@AWMA.ORG>; Gunasekara, Mandy <https://urldefense.proofpoint.com/v2/url?u=http-3A__Gunasekara.Mandy-40epa.gov&d=DwIGaQ&c=euGZstcaTDllvimEN8b7jXrwqOf-v5A_CdpgnVfiiMM&r=I2EakDkHCz8LPL8q80bkmABpXnftzypKkbsoPJKgRJO&m=aZ5fzhDcXeY-GR2wuzl3RBQgzl1i49naGYj_zNYfaVA&s=zZWnt_kvW6E6LJdbc3KFlPlLhcm-4g24VaKTHfpuZJE&e=>; jcmuffat <jcmuffat@yahoo.com>
Subject: RE: EXTERNAL: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA

Alex, What can we do to resolve the scheduling issue? Do we need to find a last minute replacement? It is probably too late to reflect the change in the Final Program.

Flint Webb, P.E.
C.Flint.Webb@Leidos.com
Baltimore-Washington Chapter: Vice Chair Technical Council: Climate Change Division Vice Chair Finding Common Ground on Climate Change Mitigation and Adaptation:
General Conference Chair
South Atlantic States Section: Director
Air & Waste Management Association
Work: 571-526-7706
Cell: 703-582-8094

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, October 02, 2017 11:59 AM
To: Webb, C. F. [US-US]; Dominguez, Alexander
Cc: William L. Wehrum; cfontanesi@awma.org
Subject: Re: EXTERNAL: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA

I have a scheduling issue on the 10th that needs to be worked out. I apologize. Please work with Alex (CC'd).

Sent from my iPhone

> On Oct 2, 2017, at 11:49 AM, Webb, C. Flint <C.FLINT.WEBB@leidos.com> wrote:
>
> Thank you for stepping up to keynote our conference at the at the DoubleTree hotel at 300 Army Navy Drive, Arlington, VA, October 10th. As General Conference Chair, I will have the honor of introducing you and I wanted to go over a few things ahead of time.
>

> Bio: Please provide me with a brief bio for me to use to introduce you. How do you want us to show your name in the program?
> 1) Amanda (Mandy) Gunasekara, Senior Policy Advisor to the Administrator for the Office of Air and Radiation, U.S. EPA
> 2) Amanda Gunasekara, ...
> 3) Mandy Gunasekara, ...
>
> Speaker's Breakfast: There will be a speaker's Breakfast. There is a Presenter's Breakfast 7:30-8:30 am. There will be tables set up for each conference session. I will be at the Climate Communication Panel Session table. I would recommend that you come to the Breakfast so you can find out about any last-minute changes. You can also check the web site https://www.awma.org/content.asp?admin=Y&contentid=311 for the final program.
>
> Presentation: Pleas provide me with your PowerPoint presentation and I will load it onto the computer for presentation.
>
> Schedule: After the Presenter's Breakfast at 8:30-8:40 am I am scheduled to make a few welcoming remarks after which I will introduce you. Please try to keep your presentation to 20-30 minutes so there is adequate time for questions and answers. I will give you 5, 3 and 2 minute warning using hand signals. After your presentation I will thank you and introduce Clara Poffenberger who will then introduce the Climate Policy Update Panel. Our understanding is that you will not be able to join us on the panel, but if that is correct let me know and we can include you on the panel. The panel is scheduled to run from 9:10-10:10 am.
>
> If you have ANY questions please don't hesitate to contact me or Cindy Fontanesi (copied on this e-mail). Cindy is our conference planner.
>
> See you on the 10th!
>
> Flint Webb, P.E.
> C.Flint.Webb@Leidos.com
> Baltimore-Washington Chapter: Vice Chair Technical Council: Climate
> Change Division Vice Chair Finding Common Ground on Climate Change
> Mitigation and Adaptation:
> General Conference Chair
> South Atlantic States Section: Director Air & Waste Management
> Association
> Work: 571-526-7706
> Cell: 703-582-8094
> -----Original Message-----
> From: Jeffry Muffat [mailto:jcmuffat@yahoo.com]
> Sent: Thursday, September 14, 2017 8:08 AM
> To: gunasekara.mandy@epa.gov
> Cc: William L. Wehrum; cfontanesi@awma.org
> Subject: EXTERNAL: A&WMA's Conference "Finding Common Ground on
> Climate Change Mitigation and Adaption" Scheduled for October 10th and
> 11th in Arlington VA
>
> Mandy:
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. The Conference is scheduled for Oct 10-11, 2017 in Arlington, VA and promises to be a great opportunity to exchange meaningful information on the current thinking relative to climate change and how we can mitigate any adverse effects and adapt to the potential consequences. The Association values EPA's thinking and is excited to provide the forum for discussion to our membership and other parties involved in the discussion.
>
> Bill Wehrum said that you planned to check with Administrator Pruitt one last time to see if he was available to Keynote and it would be great if he wanted to speak. However, our intent at this time is to list you in the Program at the Keynoter and then to send out a special mailing/notice announcing Administrator Pruitt as the Keynoter should he decide to speak.
>
> Cindy Fontanesi from A&WMA Headquarters in Pittsburgh will be in touch with you today to work out the details.
>
> Again, thank you so much for agreeing to speak at our upcoming Conference.
>
> Jeff Muffat
> Retired Manager of 3M Environmental Reg Affairs Treasurer of Air & Waste Management Association .

Message

From: Jennifer McDowell [jmcdowell@mema.org]
on behalf of Ann Wilson [awilson@MEMA.ORG]
Sent: 10/4/2017 6:44:41 PM
CC: Cindy Sebrell [csebrell@mema.org]; Briana Huxley [bhuxley@mema.org]
Subject: Join Us Next Week for "A World Without NAFTA? A Look at the Future Through the Lens of the Motor Vehicle Industry"

You're Invited to
MEMA's Policy Breakfast Series:
A World Without NAFTA? A Look at the Future Through the Lens of the Motor Vehicle Industry
Thursday, October 12, 2017 | 9:30 – 10:30 a.m.
2103 Rayburn House Office Building | Washington, DC
Register Here

President Trump has indicated that if a satisfactory agreement is not met with Canada and Mexico, the U.S. could withdraw from the North American Free Trade Agreement (NAFTA). What would a world without this 24-year-old trade agreement look like? Informed by new data illustrating how a NAFTA withdrawal would impact the automotive industry, we will take a deep dive into some of the challenges including rules of origin, sourcing materials and reshoring jobs, and other aspects of NAFTA that pertain specifically to motor vehicle manufacturing. After a presentation of the new data by the Boston Consulting Group, the panel will include a lively conversation with MEMA, the leading trade association for motor vehicle parts manufacturers, representatives from the motor vehicle industry, and manufacturing executives who can give a real-world perspective on the challenges a world without NAFTA would bring to American businesses.

Agenda:

- Program Introduction by Bill Long, Executive Vice President, Government Affairs, MEMA: 9:30 a.m.
- BCG NAFTA Study Presentation: 9:35 a.m.
- Panel Discussion: 9:50 a.m.
- Questions: 10:20 a.m.

Panelists:

- Xavier Mosquet, Senior Partner & Managing Director, the Boston Consulting Group
- Ian Mussleman, Director, Government Affairs, Continental
- Charles Uthus, Vice President for International Policy, American Automotive Policy Council
- Moderated by: Ann Wilson, Senior Vice President, Government Affairs, Motor & Equipment Manufacturers Association

Regards,

Ann Wilson
Senior Vice President of Government Affairs
Motor & Equipment Manufacturers Association
1030 15th St. NW
Suite 500 East
Washington, DC 20005

(202) 312-9246 (office)
(202) 320-7293 (cell)

Message

From: Spencer, Stuart [SPENCER@adeq.state.ar.us]
Sent: 10/13/2017 2:36:35 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Draft RH SIP and supporting docs part 1
Attachments: 6_RH SIP_Intro_Clean_10_12_17.docx; Visibility Progress.xlsx; AECC_Bailey_McClellan_AO.docx; DOMTAR_Ashdown_AO.docx; Entergy AO CLEAN 10_12_17 B.docx; Entergy AO NOx and LSC CLEAN.docx; Entergy AO NOx and LSC.docx; Settlement ADEQ Response.docx; SWEPCO_Flint Creek AO NOx.docx; SWEPCO_Flint Creek AO.docx

Mandy,

Thanks again for the call yesterday. Per our conversation, I'm sending Arkansas's draft Regional Haze SIP and associated docs. This will be part 1 of 4.

Call if you have any questions!

Sincerely,

Stuart Spencer
Associate Director- Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118
Ph. # (501) 682-0750
Fax # (501) 682-0880
E-mail: SPENCER@adeq.state.ar.us
Web: http://www.adeq.state.ar.us

This e-mail and any files transmitted with it are the property of the Arkansas Department of Environmental Quality, and are intended solely for the use of the individual or entity to whom this email is addressed. If you are not the named recipient(s) or otherwise have reason to believe that you have received this message in error, please notify the sender at (501) 682-0750 and delete this message immediately from your computer. Any other use, retention, dissemination, forwarding, printing or copying of this email is strictly prohibited.

Message

From: maureen@dc-groupllc.com [maureen@dc-groupllc.com]
Sent: 9/20/2017 1:06:20 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Request for a meeting on behalf of the American Biogas Council

Dear Ms. Gunasekara,

I wanted to ensure you had received the email below.

The American Biogas Council very much looks forward to hearing back from you.

Best,

Maureen

Maureen J. Walsh

Director of Federal Policy
American Biogas Council

1211 Connecticut Avenue NW, Suite 650
Washington, DC 20036
1 (202) 681-6092

maureen@dc-groupllc.com

Growing the Anaerobic Digestion and Biogas Industry

Find us on: the web | twitter | linkedin | youtube | flickr

On Thu, Sep 7, 2017 at 9:59 AM, maureen@dc-groupllc.com <maureen@dc-groupllc.com> wrote:

> Dear Ms. Gunasekara,
>
> I am reaching out to you today on behalf of the American Biogas Council (ABC)- a Washington, D.C. based trade organization focused around anaerobic digestion technologies.
>
> The ABC's mission is to create jobs, energy independence and environmental sustainability by growing the U.S. biogas industry. The ABC represents over 200 organizations across the renewable energy, agricultural, waste and wastewater management, and

transportation industries, including facility owners /operators, manufacturers of tanks, engines, and other equipment, engineering firms, project developers, legal and accounting firms, educational organizations and institutions, utilities, financiers and lenders, and local and regional governments.

The ABC interacts with many different aspects of the EPA including the Office of Air and Radiation, Office of Land and Emergency Management, Office of Water, AgStar, LMOP and others. As Administrator Pruitt's Senior Policy Advisor for the Office of Air and Radiation, we would very much like to schedule an opportunity to speak to you about the Renewable Fuel Standard. Biogas derived CNG and LNG have a significant role to play in this program. The ABC wants to do all it can to ensure the RFS continues drive growth in the rural economy and in U.S. biofuels.

Thank you in advance for your assistance and we look forward to hearing back from you.

Very kind regards,

Maureen

Maureen J. Walsh

Director of Federal Policy
American Biogas Council

1211 Connecticut Avenue NW, Suite 650
Washington, DC 20036
1 (202) 681-6092

maureen@dc-groupllc.com

Growing the Anaerobic Digestion and Biogas Industry

Find us on: the web | twitter | linkedin | youtube | flickr

Message

From: Carrie Annand, BPA [carrie@usabiomass.org]
Sent: 9/19/2017 9:50:45 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Bob Cleaves [bob@usabiomass.org]
Subject: Thanks!
Attachments: BPA Follow Up Letter to EPA 9.19.17.pdf

Hi Mandy, we really appreciate your meeting with us to discuss our proposal to allow biomass, waste-to-energy and biogas facilities to qualify under the RFS for powering electric vehicles.

I'm sending you a follow-up letter, attached, to answer some of the questions you had during the meeting and to outline our concept for you in writing.

Please don't hesitate to reach out with any questions!

Thanks again.

Carrie Annand

--
Carrie Annand
Executive Director

Mobile: (202) 494-2493
601 New Jersey Ave. NW, Suite 660 / Washington, DC / 20001
Twitter: @USABiomass
www.usabiomass.org

BIOMASS POWER ASSOCIATION

BIOMASS POWER ASSOCIATION

September 19, 2017

Mandy Gunasekara
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20004

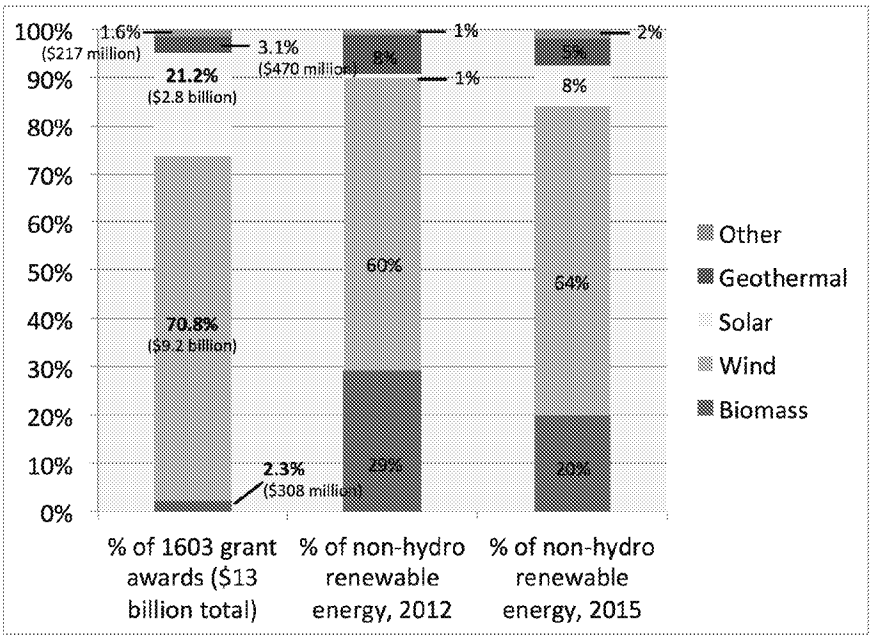
Dear Mandy,

Thank you for meeting with us to discuss our proposal to allow electricity from biomass, biogas and waste-to-energy facilities to qualify as D3 cellulosic fuels when used for transportation under the Renewable Fuel Standard. We wanted to follow up with you to answer a few of your questions and to provide an outline of the proposal in writing.

Our members across the country purchase organic "leftovers" like forestry residues and agricultural byproducts to generate so-called "baseload" electricity that is delivered to the grid. Biomass power facilities are located primarily in rural areas, providing a market and a disposal option for low-value materials while creating more jobs per unit of energy than any other renewable form of energy. Also, as a result of the devastating forest fires in the West, our facilities are considered critical infrastructure for helping the federal government fight these fires.

Despite these valuable economic and public benefits, many facilities are struggling due to the current low-priced power market. Compounding the problems posed by inexpensive natural gas is a lopsided federal renewable energy policy that historically picked "winners and losers." To make this point, we shared with you a chart that shows the funding awarded to non-hydropower renewable energy sources through the Department of the Treasury's 1603 program, part of the 2009 Stimulus Package. Well over $10 billion went to wind and solar projects, while only a small portion to biomass projects. If you compare the breakdown of funding for each technology, dramatically more funding went to wind and solar than other forms of energy. As a result, in 2015, the latest year with data available from the Energy Information Administration, wind and solar represented much larger shares of the non-hydropower renewable energy market.

Choosing Winners & Losers: Vastly More Funding for Wind and Solar Led to Growth; Biomass Losing Market Share

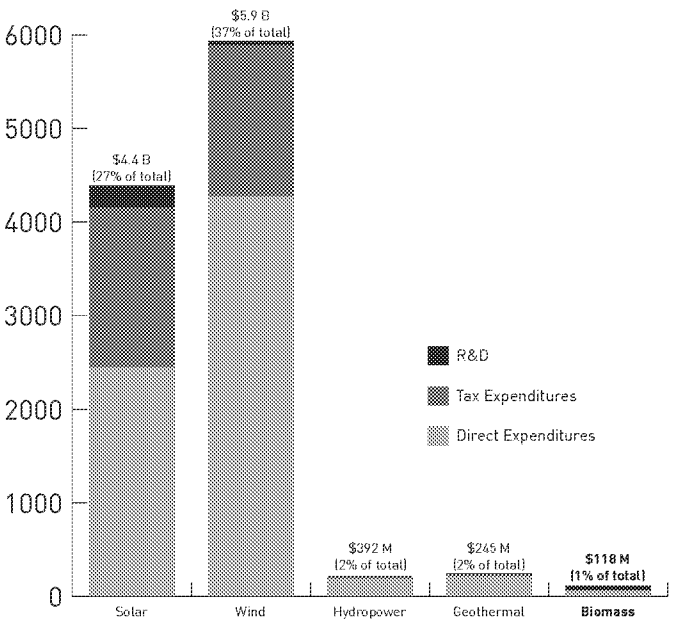


The below chart tells a similar story. In 2013, after the 1603 program ended, the federal government still spent more than $10 billion in research and development, tax expenditures and direct expenditures on wind and solar, while biomass received slightly more than 1% of that support.

Fiscal Year 2013 Electricity Production Subsidies and Support

Millions, 2013 US$

Source: U.S. Energy Information Administration



Despite the repeal/expiration of these Obama-era programs, the harm is long lasting. Because of these massive subsidies, wind and solar can afford to sell power on the grid well into the future at artificially low prices. In fact, biomass facilities should be much more valuable at a time when tree mortality and beetle blight are threatening forests out West and creating hazardous fuels that must be cleared out forests to avoid catastrophic fire. Unfortunately, our members are not compensated for these services. As a result, many companies are forced to idle or permanently shutter facilities as their customers decline to renew their contracts in favor of cheaper natural gas, wind or solar.

EPA can help address the crisis in our industry through its implementation of the Renewable Fuel Standard. As you know, the production of biofuels has accelerated at a slower pace than expected, and as a result the adjusted volumes have fallen far short of the statutory targets. The challenge is particularly acute for cellulosic biofuels (the D3 category) where less than 10% of the gallons mandated by Congress were actually produced in 2016. The D3 market is woefully under served and illiquid, resulting in a "tax" to obligated parties while denying a competitive market for buyers and sellers. In short, the D3 category needs greater market participants.

In 2014, EPA recognized that biomass-derived electricity would qualify for D3 RINs, but the Agency has failed since then to register a single facility and has yet to adopt final rules for our industry. As we discussed, we believe there is a common sense, simple approach to the electricity pathway of the RFS. Under our proposal, each generator would register in the EMTS system and be the generator of a RIN for each kilowatt hour of electricity *produced*. EPA would track the overall electricity *consumed* by electric vehicles. RINs would be awarded to each generator based on the amount that contributes to overall consumption. Any other approach is overly complex, invites fraud and abuse, and fails to award the value the generator of the fuel.

In summary, this approach is simple, straightforward, fits within the statutory framework, eliminates the chances for fraud, and promotes sensible forest management and rural jobs while not incentivizing any particular transportation fuel. We are very grateful for your time and consideration for this proposal. We are available at any time should you have questions. Please contact me at 207-228-7376 or bob@usabiomass.org, or Carrie Annand at 202-494-2493 or carrie@usabiomass.org.

Sincerely,

Robert E. Cleaves IV

Message

From: David Vitter [dvitter@mercuryllc.com]
Sent: 9/29/2017 5:14:35 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: AHRI Speaking Invitation to Administrator Pruitt, Sunday Evening, November 12, Trump National Doral Resort, Miami

Thank you very much.

Sent from my iPhone

Mercury.
David Vitter
Co-Chairman
300 Tingey Street SE | Suite 202
Washington, DC | 20003
202.261.4000 office
www.mercuryllc.com

On Sep 29, 2017, at 12:12 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hayley ford is the best point of contact. Ford.Hayley@epa.gov
>
> I'll also forward it along with a note of endorsement
>
> Sent from my iPhone
>
> On Sep 29, 2017, at 1:10 PM, David Vitter <dvitter@mercuryllc.com> wrote:
>
> > I was actually asking you to help us follow on AHRI's invite to Administrator Pruitt. 1) Can you ask his office for a response (hopefully positive). This is a great, substantial, very supportive industry group. 2) Who in his office should I follow up with directly?
> >
> > Sent from my iPhone
> >
> > David Vitter
> > Co-Chairman
> > 300 Tingey Street SE | Suite 202
> > Washington, DC | 20003
> > 202.261.4000 office
> > www.mercuryllc.com
> >
> > On Sep 29, 2017, at 11:58 AM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
> >
> > > Hi Senator,

I apologize for the delayed response. I will be in Germany for the climate conference, so unfortunately not available for the Miami conference.
Thank you for the invite and please keep me in mind for future opportunities.
Best,
Mandy

From: David Vitter [mailto:dvitter@mercuryllc.com]
Sent: Friday, September 29, 2017 12:54 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Fwd: AHRI Speaking Invitation to Administrator Pruitt, Sunday Evening, November 12, Trump National Doral Resort, Miami

Mandy--Any word on this?

Sent from my iPhone

David Vitter
Co-Chairman
300 Tingey Street SE | Suite 202
Washington, DC | 20003
202.261.4000 office
www.mercuryllc.com

Begin forwarded message:

> **From:** "David Vitter" <dvitter@mercuryllc.com>
> **To:** "Gunasekara.Mandy@epa.gov" <Gunasekara.Mandy@epa.gov>
> **Subject: AHRI Speaking Invitation to Administrator Pruitt, Sunday Evening, November 12, Trump National Doral Resort, Miami**
>
> Mandy-- David Vitter here. Our client AHRI, with whom you met recently on the SNAP issue, has invited Administrator Pruitt to the major speaking opportunity referenced above at their national conference. AHRI is a friend and ally of this Administration and EPA on a broad host of issues and would really like to host and hear from the Administrator.
>
> Two questions: 1) Can you highlight the invitation to the Administrator and help us get a (hopefully positive) response? 2) Who should I follow up with re his schedule?
>
> Many thanks.

This email is intended only for the person or entity to which it is addressed and may contain information that is privileged, confidential or otherwise protected from disclosure. Dissemination, distribution, or copying of this email or the information herein by anyone other than the intended recipient, or an employee or agent responsible for delivering the message to the intended recipient, is prohibited. If you have received this email in error, please immediately notify us by calling our Network Operations Center at +1 855 237 8324.

Message

From: Paul Bleiberg [pbleiberg@nmpf.org]
Sent: 9/21/2017 12:21:17 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Meeting question

Thanks Mandy! I believe Oct 2-3. Let me know if I should direct them to you.

Sent from my iPhone

> On Sep 20, 2017, at 8:19 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>
> Hey Paul,
> Air is me and water is my colleague Sarah Greenwalt. When will they be in town?
> Best,
> Mandy
>
> Sent from my iPhone
>
>> On Sep 20, 2017, at 6:53 PM, Paul Bleiberg <pbleiberg@nmpf.org> wrote:
>>
>> Mandy,
>>
>> Hope you're doing well. Hopefully an easy question - one of our state dairy associations is coming to town and would like to meet with EPA staff to discuss some air and water issues. Do you recommend a particular person for them to contact?
>>
>> Thanks,
>> Paul
>>
>> Paul Bleiberg
>> Senior Director, Government Relations
>> National Milk Producers Federation
>>
>> Sent from my iPhone

Message

From: Paul Cicio [PCicio@carbonleaf.net]
Sent: 9/20/2017 1:05:40 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: NSR

Thank you Mandy.

Alex, what is your telephone number? Lets discuss alternative dates. Thanks.

Paul Cicio
President
Industrial Energy Consumers of America
1776 K Street, NW, Suite 720
Washington, DC 20006
(O) 202-223-1661
(C) 703-216-7402
www.ieca-us.org

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 2,600 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Wednesday, September 20, 2017 12:06 AM
To: Paul Cicio <PCicio@carbonleaf.net>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: NSR

Hi Paul, I'm happy to discuss. Looking at the schedule, early October would be best. I've CC'd Alex who can help with the logistics. It
will also be good to have our Office of Policy (Samantha and Brittany) in on the discussion.
I look forward to connecting soon.
Best,
Mandy

Sent from my iPhone

On Sep 19, 2017, at 2:11 PM, Paul Cicio <PCicio@carbonleaf.net> wrote:

> Hi Mandy,
> I just noticed the interest on the part of Pruitt to address NST for power plants. We would like to work with Pruitt to address NSR in manufacturing. NSR is under a different part of the CAA than for power plants.

When can we discuss this?

Best

Paul Cicio
President
Industrial Energy Consumers of America
1776 K Street, NW, Suite 720
Washington, DC 20006
(O) 202-223-1661
(C) 703-216-7402
www.ieca-us.org

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 2,600 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

Message

From: Sarah Criser Elwell [selwell@forumclubpb.com]
Sent: 9/25/2017 2:04:49 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Speaking Opportunity with 800 South Florida Leaders for Administrator Pruitt

Thank you, Mandy! Have a great week!

Sarah Criser Elwell
Executive Director
Forum Club of the Palm Beaches
561-304-0570

On Sep 24, 2017, at 1:25 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Sarah,
> Thank you for the invitation. I will pass it on to the scheduling/advance team to see what could work.
> Hope you are well!
> Mandy
>
> Sent from my iPhone
>
> On Sep 22, 2017, at 6:18 PM, Sarah Criser Elwell <selwell@forumclubpb.com> wrote:
>
>> Mandy,
>>
>> Congrats on your new role at the EPA! Very well deserved... you were one of the hardest workers I knew while on the Hill and I am extremely excited for you!
>>
>> I apologize for the late-Friday email, but I wanted to make sure I got this information to you ASAP. As I mentioned earlier, I have a speaking opportunity for Administrator Pruitt that may be of interest.
>>
>> Last year, I became the Executive Director of Florida's largest nonpartisan political and public affairs organization. Our membership is capped at 800 of South Florida's top business, political and community leaders, and I am responsible for hosting 9-12 events each year with national thought leaders, like Administrator Pruitt, in an effort to stimulate thought and promote dialogue on a variety of topics. Our past speakers include former Presidents of the United States, Cabinet officials, heads of state, four star generals, national media personalities, historians and more. For more information about the organization, please visit our website: www.forumclubpalmbeach.org.
>>
>> I am currently in the process of booking late December through May events and wondered if Administrator Pruitt might be interested in joining us this season. Should this be of interest, the event would include a 20-minute speech followed by a 20-minute Q&A moderated by our Board President with questions submitted by the audience via notecards. It would be held at the Palm Beach County

Convention Center or the Kravis Center for the Performing Arts in West Palm Beach, beginning promptly at noon and concluding no later than 1:15 p.m.

For reference, our events typically attract anywhere from 500-1,000 attendees depending on the time of year, the capacity of the venue, topic being discussed and the speaker himself. In addition, events that coincide with Palm Beach's social season (and this event would), tend to be our best attended. While I wouldn't have a list of RSVPs until we release the event, it is not uncommon for there to be past and present CEOs from major corporations, current and former members of Congress, state and local officials, and the who's who of Palm Beach in attendance.

It is also important to note that we are extremely flexible with our scheduling. While our events are held on weekdays at noon, we can usually accommodate any month or date within these parameters as long as it is available at one of our venues.

As a nonprofit organization, the Forum Club offers reimbursement of first-class airfare and up to two nights accommodations at the Breakers, Palm Beach's premiere oceanfront resort. If Administrator Pruitt is a golfer, we can also arrange for a round of golf at the exclusive Jupiter Hills Country Club while he is here.

Please let me know if you have any questions and whether you believe this might be of interest to the Administrator. I appreciate your consideration and hope to have the opportunity to see you soon!

Sincerely,
Sarah

--
Sarah Criser Elwell
Executive Director
Forum Club of the Palm Beaches

Message

From: CC Conference 2017 [CCConference2017@AWMA.ORG]
Sent: 10/2/2017 3:51:46 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; jcmuffat [jcmuffat@yahoo.com]
CC: Tracy Fedkoe [TFedkoe@AWMA.ORG]
Subject: Your Presentation Title? (AWMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA)

Importance: High

Mandy,

Do you have a title for your presentation that we can include in the final printed program for the conference? Please send it today if possible.

Thank you,

Cindy Fontanesi
Conference & Events Planner
Air & Waste Management Association
One Gateway Center, Third Floor
420 Fort Duquesne Blvd
Pittsburgh, PA 15222
(t) 412-904-6031
(f)412-232-3450
Please consider the environment before printing this e-mail

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, September 18, 2017 2:43 PM
To: Cindy Fontanesi <CFontanesi@AWMA.ORG>; jcmuffat <jcmuffat@yahoo.com>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; CC Conference 2017 <CCConference2017@AWMA.ORG>
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA

That title is correct. Also, attached is my photo. Let me know if you need a different size.

-----Original Message-----
From: Cindy Fontanesi [mailto:CFontanesi@AWMA.ORG]
Sent: Monday, September 18, 2017 2:37 PM
To: jcmuffat <jcmuffat@yahoo.com>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; CC Conference 2017 <CCConference2017@AWMA.ORG>
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA
Importance: High

Hello Jeff & Mandy,

Can one of you please confirm Mandy's official title? This is what we found online:
Senior Policy Advisor to the Administrator for the Office of Air and Radiation

Also, if you have a photo of Mandy to send to us that would be great too. Please let me know if you have any questions.

Thank you again,

Cindy Fontanesi
Conference & Events Planner
Air & Waste Management Association
One Gateway Center, Third Floor
420 Fort Duquesne Blvd
Pittsburgh, PA 15222
(t) 412-904-6031
(f)412-232-3450
Please consider the environment before printing this e-mail

> On Sep 14, 2017, at 2:34 PM, Cindy Fontanesi <CFontanesi@AWMA.ORG> wrote:
>
> Hi Mandy,
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. For now, I need your preferred name and title, the title of your Keynote, and your mailing address so that we can get you officially registered for the conference. Also, please let me know if you have any special requirements for your Keynote. We will provide the standard set for audiovisuals which is an LCD projector, laptop computer, screen, laser pointer, and microphone.
>
> You are scheduled to present on Tuesday, October 10, 2017 from 8:30 am - 9:00 am. There will be a Presenters' Meeting at 7:30 am on the day of your involvement. The format of the program is discussed at this time. The Presenters' Meeting is also a good time to load your presentation in the session room and check your audiovisuals.
>
> If you'd like to take a look at the preliminary program for the conference, it can be found on our website at https://www.awma.org/climatechange. We will add your Keynote information to the conference website asap and to the final program, which will be released to the public on September 29th.
>
> The conference is being held at the DoubleTree by Hilton Washington DC - Crystal City - 300 Army Navy Drive - Arlington, VA 22202. Please let me know if you have any questions or needs along the way. I look forward to working with you and meeting you at the conference in a few weeks!
>
> Thank you,
>
> Cindy Fontanesi
> Conference & Events Planner
> Air & Waste Management Association
> One Gateway Center, Third Floor
> 420 Fort Duquesne Blvd
> Pittsburgh, PA 15222
> (t) 412-904-6031
> (f)412-232-3450
> Please consider the environment before printing this e-mail
>
>
>
> -----Original Message-----
> From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
> Sent: Thursday, September 14, 2017 9:26 AM
> To: jcmuffat <jcmuffat@yahoo.com>
> Cc: William L. Wehrum <wwehrum@hunton.com>; Cindy Fontanesi <CFontanesi@AWMA.ORG>
> Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Hi Jeff,
> Thank you for the information and I look forward to connecting with Cindy.
> Best,
> Mandy
>
> -----Original Message-----
> From: Jeffry Muffat [mailto:jcmuffat@yahoo.com]
> Sent: Thursday, September 14, 2017 8:08 AM
> To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> Cc: William L. Wehrum <wwehrum@hunton.com>; cfontanesi@awma.org
> Subject: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Mandy:
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. The Conference is scheduled for Oct 10-11, 2017 in Arlington, VA and promises to be a great opportunity to exchange meaningful information on the current thinking relative to climate change and how we can mitigate any adverse effects and adapt to the potential consequences. The Association values EPA's thinking and is excited to provide the forum for discussion to our membership and other parties involved in the discussion.
>
> Bill Wehrum said that you planned to check with Administrator Pruitt one last time to see if he was available to Keynote and it would be great if he wanted to speak. However, our intent at this time is to list you in the Program at the Keynoter and then to send out a special mailing/notice announcing Administrator Pruitt as the Keynoter should he decide to speak.
>
> Cindy Fontanesi from A&WMA Headquarters in Pittsburgh will be in touch with you today to work out the details.
>
> Again, thank you so much for agreeing to speak at our upcoming Conference.
>

> Jeff Muffat
> Retired Manager of 3M Environmental Reg Affairs Treasurer of Air & Waste Management Association .
>
>
> ----------
>
> This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
> https://us1.proofpointessentials.com/index01.php?mod_id=11&mod_option=logitem&mail_id=1505395557-Zfwis8S5ZWjM&r_address=cfontanesi%40awma.org&report=

.

This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
https://us1.proofpointessentials.com/index01.php?mod_id &mod_option=gitem&mail_id 05418758-QepsfQTnqxHw&r_address►ontanesi%40awma.org&report=

Message

From: Jerry Jung Personal Email / Ex. 6
Sent: 9/28/2017 4:03:27 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RIN market

Hi Mandy,

It was good meeting you last summer. I have continued to advocate for ethanol mandate reform and follow up on Administrator Pruitt's request to analyze the RIN market. Recently he mailed me a note asking me to share my thoughts with you on that topic.

The short answer is that it is very challenging to quantify the various demand curves that impact RIN pricing. As you know, legislation is being drafted in both chambers of Congress that would modify the RFS going forward. The Senate is looking at giving a green light to E15 but ending all mandates in 2022. The House under Congressmen Shimkus and Walden have indicted that they will have something finalized this fall.

The following concept has garnered some interest in both the House and Senate:

* Eliminate the RIN market, using RINs only to keep track of refiner compliance with mandates.
* For those refiners that do not meet mandated ethanol levels, assess a fixed charge per gallon of ethanol shortfall.
* The shortfall revenues would be forwarded to the U.S. Treasury and earmarked for a specific purpose such as the Conservation Reserve Program.

The rationale behind this concept is multifaceted. First of all, the RIN price could be set at a level more in keeping with sound policy objectives. The Administrator told me in our initial meeting that RIN pricing in the 10-20 cent range would make more sense than the current levels. As you know, the current practice creates uncertainty and adds significant costs to refineries and ultimately consumers. It is a windfall for blenders--in essence a hidden subsidy that does not benefit the public. Refiners would welcome some certainty in their planning process. This approach could largely make moot point of obligation issues and I believe would have the support of refiners as well as consumers. The passage of E15 into law would impact RIN in a manner dependent upon the "fine print." Fixed pricing would address this issue.

Depending on the use for the additional revenue, passage of a reform bill could gain additional support from the environmental community. Earmarking for CRP programs would also cushion the agricultural sector as it transitions to growing crops that add value to the economy.

What are your thoughts on this approach? I will be meeting with Congressional leaders in October and it would helpful to know if the EPA would support this concept.

I've attached a picture I took a couple of days ago while fishing on Lake Erie. A recent University of Michigan study concluded that 85% of the nutrient overload in the Great Lake is agricultural in origin. That's toxic algae with a nuclear power plant in the background.

Best,

Jerry Jung
Personal Phone / Ex. 6

Preview attachment IMG_0474.JPG

IMG_0474.JPG
322 KB

hment IMG_0474.JPG

IMG_0474.JPG
322 KB

Message

From: Kyle Harris [kharris@corn.org]
Sent: 10/3/2017 4:18:44 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Biogenic CO2

Mandy,

Thanks again for speaking with us last Friday and giving us an update on where the Biogenic CO2 Issue currently stands. We want to be as supportive of your efforts as possible, please do not hesitate to reach out if there is anything that CRA or the Biogenic CO2 Coalition more broadly can do in this process.

Best,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

Please consider the environment before printing this email

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Thursday, September 21, 2017 11:30 AM
To: Keniece Barbee <kbarbee@corn.org>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Confirmed for 12:30PM on Friday the 29th

Same number as last night if we could.

Conference
Passcode: 2 **Personal Phone / Ex. 6**

If you would like to send a calendar invite that would be great. I will also send one internally for our folks.

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Keniece Barbee [mailto:kbarbee@corn.org]
Sent: Thursday, September 21, 2017 9:28 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Hello Alex,

Can we please schedule for 12:30PM on Friday September 29th. Would you please send calendar invite, or I am happy to with call in number?

Thank you.

Regards,

Keniece Barbee
Assistant to President and C.E.O.
Corn Refiners Association

CORN REFINERS ASSOCIATION

1701 Pennsylvania Avenue, N.W.
Suite 950
Washington, DC 20006
Main: (202) 331-1634
Direct: (202) 534-3491
Fax: (202) 331-2054
www.corn.org

This message and any files transmitted with it are confidential and intended solely for the use of the individual or entity to whom they are addressed. If you are not the intended recipient, please immediately advise the sender by reply e-mail that this message has been inadvertently transmitted to you and delete this e-mail from your system. Thank you for your cooperation.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Wednesday, September 20, 2017 6:24 PM
To: Kyle Harris <kharris@corn.org>; Keniece Barbee <kbarbee@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Kyle and Keniece - Per our discussion it looks like the best time to reschedule is for next Friday, September 29. Would either 12:00PM, 12:30 or 4:00 – close work on your end?

Alex

From: Kyle Harris [mailto:kharris@corn.org]
Sent: Wednesday, September 20, 2017 5:32 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Ok we are standing by.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Wednesday, September 20, 2017 5:30 PM
To: Kyle Harris <kharris@corn.org>
Cc: Keniece Barbee <kbarbee@corn.org>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Biogenic CO2

Kyle - we are still in with the administrator I apologize as this has happened a few times now. I will touch base when I get out but Mandy is going to be here a while.

Sent from my iPhone

On Sep 20, 2017, at 5:22 PM, Kyle Harris <kharris@corn.org> wrote:

> Hi Alex, we are on the line whenever you guys are ready.
>
> Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image001.png>

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Wednesday, September 20, 2017 9:39 AM
To: Keniece Barbee <kbarbee@corn.org>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Confirmed – yes still the same number - and copy will do going forward

From: Keniece Barbee [mailto:kbarbee@corn.org]
Sent: Wednesday, September 20, 2017 9:23 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Hi Alex,

I've moved the call to 5:15PM ET on the calendar.

Can you please confirm that the following is still the correct call in for today?
866-299-3188, Passcode: 202-564-6082

Also, apologies that I didn't see your email last night when you sent. Going forward please feel free to call my cell for any last minute changes.

Many thanks for your efforts.

Regards,

Keniece Barbee
Assistant to President and C.E.O.
Corn Refiners Association
<image001.png>

1701 Pennsylvania Avenue, N.W.
Suite 950
Washington, DC 20006
Main: (202) 331-1634
Direct: (202) 534-3491
Fax: (202) 331-2054
www.corn.org

This message and any files transmitted with it are confidential and intended solely for the use of the individual or entity to whom they are addressed. If you are not the intended recipient, please immediately advise the sender by reply e-mail that this message has been inadvertently transmitted to you and delete this e-mail from your system. Thank you for your cooperation.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Wednesday, September 20, 2017 9:20 AM
To: Kyle Harris <kharris@corn.org>; Keniece Barbee <kbarbee@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Great. Thank you for the flexibility.

From: Kyle Harris [mailto:kharris@corn.org]
Sent: Wednesday, September 20, 2017 8:57 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Keniece Barbee <kbarbee@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Alex,

Sorry for just seeing this. 515 will have to do- we are looking forward to it.

Thanks,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image001.png>

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 19, 2017 8:14 PM
To: Keniece Barbee <kbarbee@corn.org>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Biogenic CO2

Keniece and Kyle - Are you able to move the 10AM call tomorrow to either 8:45 or 5:15?

Alex

Sent from my iPhone

On Sep 8, 2017, at 10:07 AM, Keniece Barbee <kbarbee@corn.org> wrote:

> Alex!
>
> You are the best! Thank you so much for the flexibility.
>
> Happy Friday and have a wonderful weekend.
>
> *Regards,*
>
> ***Keniece Barbee***
> *Assistant to President and C.E.O.*
> *Corn Refiners Association*
> <image001.png>

1701 Pennsylvania Avenue, N.W.
Suite 950
Washington, DC 20006
Main: (202) 331-1634
Direct: (202) 534-3491
Fax: (202) 331-2054
www.corn.org

This message and any files transmitted with it are confidential and intended solely for the use of the individual or entity to whom they are addressed. If you are not the intended recipient, please immediately advise the sender by reply e-mail that this message has been inadvertently transmitted to you and delete this e-mail from your system. Thank you for your cooperation.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Friday, September 8, 2017 10:05 AM
To: Keniece Barbee <kbarbee@corn.org>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Let's do Wednesday, September 20th at 10:00AM.

Conference Line: 866-299-3188
Passcode: 202-564-6082

Anything else just let me know.

From: Keniece Barbee [mailto:kbarbee@corn.org]
Sent: Friday, September 8, 2017 9:52 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Kyle Harris <kharris@corn.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Hi Alex,

Thank you so much for your quick response to Kyle, this is very important to us.

Unfortunately, John Bode will be in flight during the time you gave on Monday 9/18 and in an all-day Board Meeting on 9/19.

Is there any time between 3-5:00PM on Monday 9/18 OR Wednesday, 9/20, 10:00AM to 1:00PM that could possibly work for this call?

Regards,

Keniece Barbee
Assistant to President and C.E.O.
Corn Refiners Association
<image001.png>

1701 Pennsylvania Avenue, N.W.
Suite 950

Washington, DC 20006
Main: (202) 331-1634
Direct: (202) 534-3491
Fax: (202) 331-2054
www.corn.org

This message and any files transmitted with it are confidential and intended solely for the use of the individual or entity to whom they are addressed. If you are not the intended recipient, please immediately advise the sender by reply e-mail that this message has been inadvertently transmitted to you and delete this e-mail from your system. Thank you for your cooperation.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Friday, September 8, 2017 9:29 AM
To: Kyle Harris <kharris@corn.org>
Cc: Keniece Barbee <kbarbee@corn.org>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Biogenic CO2

Hey Kyle,

Happy to set something up. Could you do a call Monday, September 18th at 11:30AM or Tuesday, September 19th at 2:00PM?

Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Kyle Harris [mailto:kharris@corn.org]
Sent: Thursday, September 7, 2017 10:17 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>; Keniece Barbee <kbarbee@corn.org>
Subject: RE: Biogenic CO2
Importance: High

Mandy,

I hope you were able to enjoy the Labor Day Weekend.

Thanks again for meeting with us on July 26th, we thought it was a very productive meeting and hope to maintain an open dialogue with you moving forward.

We were hoping to get a follow up call with you and your core decision makers on the calendar in the coming weeks as we work towards a resolution to the biogenic issue. We participated in EPA's Science Advisory Board Public Meeting last week in Arlington. Through both written and verbal comments we stated the need to place short cycle agriculture biomass on a separate track from woody biomass. We continue to think that Biogenic CO2 from agriculture crops should not and is not properly regulated at this point in time.

We were hoping to get a follow up call with you and your core decision makers on the calendar in the coming weeks as we work towards a resolution to the biogenic issue.

Please do not hesitate to reach out to me should you need any further information or clarification.

Thanks in advance,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Kyle Harris
Sent: Thursday, August 24, 2017 11:44 AM
To: 'Gunasekara, Mandy' <Gunasekara.Mandy@epa.gov>
Cc: 'dominguez.alexander@epa.gov' <dominguez.alexander@epa.gov>; Keniece Barbee <kbarbee@corn.org>
Subject: RE: Biogenic CO2

Greetings Mandy,

I just wanted to follow up on my message below.

Thanks again for meeting with us on July 26th, we thought it was a very productive meeting and hope to maintain an open dialogue with you moving forward.

We were hoping to get a follow up call with you and your core decision makers on the calendar in the coming weeks as we work towards a resolution to the biogenic issue.

Please do not hesitate to reach out to me should you need any further information or clarification.

Thanks in advance,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Kyle Harris
Sent: Thursday, August 10, 2017 9:45 AM
To: 'Gunasekara, Mandy' <Gunasekara.Mandy@epa.gov>
Cc: 'dominguez.alexander@epa.gov' <dominguez.alexander@epa.gov>; Keniece Barbee <kbarbee@corn.org>
Subject: RE: Biogenic CO2

Greetings Mandy,

Thanks again for meeting with us on July 26th, we thought it was a very productive meeting and hope to maintain an open dialogue with you moving forward.

We were hoping to get a follow up call with you and your core decision makers on the calendar in the coming weeks as we work towards a resolution to the biogenic issue.

Please do not hesitate to reach out to me should you need any further information or clarification.

Thanks in advance,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn

Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Thursday, June 15, 2017 1:03 PM
To: Kyle Harris <kharris@corn.org>
Cc: David M. (Max) Williamson <maxwilliamson@williamsonlawpolicy.com>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Biogenic CO2

Kyle,

Thank you for the update and I look forward to meeting again soon. I've cc'd Alex Dominguez who can help organize the logistics.

Best,
Mandy

From: Kyle Harris [mailto:kharris@corn.org]
Sent: Tuesday, June 13, 2017 3:03 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: David M. (Max) Williamson <maxwilliamson@williamsonlawpolicy.com>
Subject: RE: Biogenic CO2
Importance: High

Mandy,

Your lawyers, the Department of Justice, have contacted us regarding our challenge to the Aircraft Rule, as a status report on our abeyance order is due to the DC Circuit June 28th. This presents a perfect opportunity to sit down and pick back up our conversation regarding the biogenic issue, and share with you our proposed resolution.

We would like to schedule a meeting at your convenience ahead of this June 28th deadline.

Best Regards,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Kyle Harris
Sent: Tuesday, May 30, 2017 4:52 PM
To: 'Gunasekara, Mandy' <Gunasekara.Mandy@epa.gov>
Cc: David M. (Max) Williamson <maxwilliamson@williamsonlawpolicy.com>
Subject: RE: Biogenic CO2

Mandy,

I hope you found time to enjoy Memorial Day Weekend. I wanted to follow-up to see if there is anything else I can provide you with to resolve the biogenic issue. Again, we are hopeful for a prompt and permanent resolution to this matter without extended rulemaking and also end all litigation over the Aircraft Rule. We believe the strategy and vehicle discussed in our May 2nd meeting will be the most effective way of accomplishing this.

We would like to schedule a follow up meeting/call at your earliest convenience to further discuss. Additionally, please let me know when may be the most appropriate time to request a meeting between Biogenic CO2 Coalition member CEOs and Administrator Pruitt.

Best Regards,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, May 08, 2017 4:53 PM
To: Kyle Harris <kharris@corn.org>
Cc: David M. (Max) Williamson <maxwilliamson@williamsonlawpolicy.com>
Subject: RE: Biogenic CO2

Thank you, Kyle. Appreciate the follow-up.
Best,
Mandy

From: Kyle Harris [mailto:kharris@corn.org]
Sent: Monday, May 8, 2017 4:50 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: David M. (Max) Williamson <maxwilliamson@williamsonlawpolicy.com>
Subject: RE: Biogenic CO2

Mandy,

I wanted to follow up and confirm that you received the case studies that I sent last week. I can understand how busy you are- and just wanted to make sure they didn't fall unnoticed to the bottom of your email inbox! Attached here should be everything that I have sent your way (or handed in person) regarding Biogenic CO2. Additionally, please find our comments on the proposed significance rule, as it's our most thorough exposition of the legal arguments surrounding this issue.

Attached you will find:

- Letter sent to Administrator Pruitt upon his confirmation
- One-page overview of the Ag-based Biogenic CO2 issue
- Case Studies developed to frame permitting issues we face
- Comments filed on the Proposed Significance Rule
- Slide deck highlighting EPA Actions/Concerns

I hope you find this information helpful, please don't hesitate to reach out should you have any questions or concerns. Again, we look forward to maintaining an open dialogue and we hope to meet with you regarding next steps in the very near future.

Best Regards,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted,

amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

From: Kyle Harris
Sent: Tuesday, May 02, 2017 4:29 PM
To: 'Gunasekara, Mandy' <Gunasekara.Mandy@epa.gov>
Subject: Biogenic CO2

Mandy,

Thank you for meeting with us today. Per our discussion, I wanted to forward you some 'case studies' that we have developed that put a story behind some of the permitting issues that the members of my association, and others in the coalition, have dealt with on a consistent basis.

I look forward to maintaining a dialogue moving forward- please do not hesitate to reach out should you need any further information. We look forward to next steps in getting this issue resolved.

Best Regards,

Kyle

Kyle A. Harris, Esq.
Manager, Environmental Affairs/ Workplace Safety
Corn Refiners Association
www.corn.org
1701 Pennsylvania Ave NW
Suite 950, Washington, DC 20006
Office: (202) 534-3501
Cell: (410) 924-2629

<image

This e-mail message may contain confidential or legally privileged information and is intended only for the use of the intended recipient(s). Any unauthorized disclosure, dissemination, distribution, copying or the taking of any action in reliance on the information herein is prohibited. E-mails are not secure and cannot be guaranteed to be error free as they can be intercepted, amended, or contain viruses. Anyone who communicates with us by e-mail is deemed to have accepted these risks. Corn Refiners Association is not responsible for errors or omissions in this message and denies any responsibility for any damage arising from the use of e-mail. Any opinion and other statement contained in this message and any attachment are solely those of the author and do not necessarily represent those of the company.

<image002.gif>

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 9/18/2017 4:28:21 PM
To: Ceglia, Lisa (CWDC) [Lisa.Ceglia@smiths.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting request

Lisa – Would 12:00PM on Wednesday the 27th work for you all? Additionally, if I can just get the list of attendees for security that would be great.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Gunasekara, Mandy
Sent: Monday, September 18, 2017 10:18 AM
To: Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>
Cc: Lyons, Troy <lyons.troy@epa.gov>; Jackson, Ryan <jackson.ryan@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Meeting request

Alex, can you help organize the logistics for this meeting please?

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 18, 2017 9:38 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Lyons, Troy <lyons.troy@epa.gov>; Jackson, Ryan <jackson.ryan@epa.gov>
Subject: Re: Meeting request

Good morning, greetings from Myrtle Beach. I had to come recover after witnessing yet another awful Bills game. Hope y'all had a great weekend. Just wanted to check in if you had a time that would work on the 27th? We currently have a few requests pending, but wanted to work around you. Our only conflict as of now is at 2:00.

Thanks again for agreeing to do this. See you next week.

Lisa

PS- Troy, Baltimore D got me 20 fantasy points- wahoo!

Sent from my iPad

On Sep 11, 2017, at 4:28 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

Troy – you are still very special.
Lisa! I can't wait to catch up and look forward to the discussion with John.

From: Lyons, Troy
Sent: Monday, September 11, 2017 4:20 PM
To: Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>; Jackson, Ryan <jackson.ryan@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

Here I thought I was special….

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 11, 2017 3:27 PM
To: Jackson, Ryan <jackson.ryan@epa.gov>; Lyons, Troy <lyons.troy@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

Hi Mandy—Ryan speaks the truth ☺. Hope you are well. Let me know the best times for you all and we'll get it on the schedule.

Thanks so much!

Lisa

From: Jackson, Ryan [mailto:jackson.ryan@epa.gov]
Sent: Monday, September 11, 2017 3:24 PM
To: Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>; Lyons, Troy <lyons.troy@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

We would be happy to. I'll include Mandy your other actual favorite person to contribute too. We'll figure out the best time.

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 11, 2017 3:07 PM
To: Jackson, Ryan <jackson.ryan@epa.gov>; Lyons, Troy <lyons.troy@epa.gov>
Subject: Meeting request

Hello!!! If it isn't two of my favorite people, EVER. Now that I've adequately flattered you..

John Crane, our oil and gas supplier division, is bring John Donatiello, VP of Global products to town September 27th. John has never really done the DC meeting tour with us and we would like to take him to all the places of interest. Of course, I thought of you both. Would you have time on the 27th to discuss the Methane re-proposal and the future of other rules and regulations you see coming? Really, just any issues you think he may find fascinating.

I included the link to John Crane below. We are the manufacturer of mechanical seals, suppling sealing device technology to oil and gas, chemical, water and other facilities.

https://www.johncrane.com/

Happy to discuss in further detail prior to the meeting. Please let me know a time that will work for you and we will do our best to accommodate.

Thank you, thank you!

Lisa

Lisa M. Ceglia
Vice President
Government Relations
Smiths Group
425 Third Street, SW, Ste. 875
Washington, DC 20024
Phone: 202-777-8453
Cell: 716-863-7996

PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.

****
CAUTION: THIS MESSAGE ORIGINATED FROM THE PUBLIC INTERNET AND WAS NOT SENT FROM THE SMITHS EMAIL SYSTEM
****
PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.
PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.

Message

From: Marcus Johnson [marcus@emergingissuespolicyforum.org]
Sent: 9/27/2017 3:22:01 PM
To: Marcus Johnson [marcus@emergingissuespolicyforum.org]
Subject: 2017 EIPF DRAFT Agenda (09/27/17)
Attachments: 2017 EIPF Energy Agenda FINAL DRAFT September 27.pdf

EIPF

Emerging Issues Policy Forum

Federal Regulators
FERC Chairman Neil Chatterjee
FERC Commissioner Cheryl LaFleur
FERC Director, Office of External Affairs, Leonard Tao
EPA Sr. Policy Advisor, Office of Adm. Mandy M. Gunasekara

State Regulators
NARUC First Vice President Chairperson Ellen Nowak, WI
NARUC Taskforce on Innovation Chairman Brien Sheahan, IL
NARUC E&E Chair Nancy Lange, MN
NARUC Gas Committee Chairman Stan Wise, GA
NARUC Water Chair Mary-Anna Holden, NJ
NARUC Sub Supplier and Workforce Diversity Chair and Sub Pipeline Safety Chair Sherina Maye Edwards, IL
NARUC Sub Educ. & Research Chair John "Butch" Howard, SC
NARUC Task Force on Environmental Regulation and Generation Chairman Asim Haque, OH
NARUC Electricity Co-Vice-Chair John Rosales, IL
NARUC Crit. Infra. Co-Vice Chair Nick Wagner, IA
NARUC Water Co-Vice Chair Comer "Randy" Randall, SC
NARUC Nuclear Issues/ Waste Disposal Sub Vice-Chair Lauren "Bubba" McDonald, Jr. GA
Chairman Brad Johnson, MT
Chairman Sandy Jones, NM
Vice Chairman Robert Cicero, KY
Vice Chair Cynthia Hall, NM
Commissioner Kimberly O'Guinn, AR
Commissioner Dr. Talina Mathews, KY
Commissioner Maida Coleman, MO
Commissioner Stephen M. Stoll, MO
Commissioner Bob Anthony, OK
Commissioner Nikiya "Nikki" Hall, SC
Commissioner Jordan White, UT
Commissioner Michael Huebsch, WI
Acting Commissioner Sadzi Olivo, IL

Consumer Advocates
NASUCA President Robert Nelson, MT
NASUCA Vice President and Consumer Counsel Elin Katz, CT
NASUCA Electricity Chair Robert Mork, IN
NASUCA Secretary and Director of Consumer Advocate Division Jackie Roberts, WV
CUB Executive Director David Kolata, IL
CUB Director of Policy & Sr. Attorney Kristin Munsch, IL
OPUC Public Counsel Tonya Baer, TX

Legislators
NCSL President Senator Deb Peters, SD
NBCSL President Representative Greg Porter, IN
NHCSL Energy Task Force Member& Nevada President Pro Tempore, Senator Moises "Mo" Denis, NV
NBCSL Vice President Rep. Billy Mitchell, GA
NBCSL Energy/Trans/Env. Co-Chair Rep. Cherrish Pryer, IN
CSG Vice Chair Representative Helene Keeley, DE
NCSL Energy Supply TF Member Rep. Tom Sloan, KS
NBCSL Energy/Trans/Env. Co-Chair Rep. Angela Angel, MD
Chair Senate Energy and Public Utilities Committee Senator Martin Hunter, IL
NCSL Past President Senator Curt Bramble, UT
Assemblyman Robin Schimminger, New York

Local Government
Mayor Jonathan F. Mitchell, New Bedford, MA; USCM Energy Chair
Mayor Elizabeth Kautz, Burnsville, MN; USCM Past President
NLC Executive Director Clarence Anthony
Mayor Toni Harp, New Haven, CT; President AAMA
Mayor Catherine Pugh, Baltimore, MD; USCM

Capital Markets
Daniel Ford, CFA, Managing Director, Head of North America Utilities Equity Research, Barclays

Powering the Future 2017

Sponsored by:

MACQUARIE

EY
Building a better working world

troutman sanders

Russell Reynolds ASSOCIATES

Itron

The Eau Palm
Manalapan, FL
October 7 - 10, 2017

DRAFT

EIPF

Emerging Issues Policy Forum

Federal Regulators
FERC Chairman Neil Chatterjee
FERC Commissioner Cheryl LaFleur
FERC Director, Office of External Affairs, Leonard Tao
EPA Sr. Policy Advisor, Office of Adm. Mandy M. Gunasekara

State Regulators
NARUC First Vice President Chairperson Ellen Nowak, WI
NARUC Taskforce on Innovation Chairman Brien Sheahan, IL
NARUC ERE Chair Nancy Lange, MN
NARUC Gas Committee Chairman Stan Wise, GA
NARUC Water Chair Mary-Anna Holden, NJ
NARUC Sub Supplier and Workforce Diversity Chair and Sub Pipeline Safety Chair Sherina Maye Edwards, IL
NARUC Sub Educ. & Research Chair John "Butch" Howard, SC
NARUC Task Force on Environmental Regulation and Generation Chairman Asim Haque, OH
NARUC Electricity Co-Vice-Chair John Rosales, IL
NARUC Crit. Infra. Co-Vice Chair Nick Wagner, IA
NARUC Water Co-Vice Chair Comer "Randy" Randall, SC
NARUC Nuclear Issues/ Waste Disposal Sub Vice-Chair Lauren "Bubba" McDonald, Jr. GA
Chairman Brad Johnson, MT
Chairman Sandy Jones, NM
Vice Chairman Robert Cicero, KY
Vice Chair Cynthia Hall, NM
Commissioner Kimberly O'Guinn, AR
Commissioner Dr. Talina Mathews, KY
Commissioner Maida Coleman, MO
Commissioner Stephen M. Stoll, MO
Commissioner Bob Anthony, OK
Commissioner Nikiya "Nikki" Hall, SC
Commissioner Jordan White, UT
Commissioner Michael Huebsch, WI
Acting Commissioner Sadzi Oliva, IL

Consumer Advocates
NASUCA President Robert Nelson, MT
NASUCA Vice President and Consumer Counsel Elin Katz, CT
NASUCA Electricity Chair Robert Mork, IN
NASUCA Secretary and Director of Consumer Advocate Division Jackie Roberts, WV
CUB Executive Director David Kolata, IL
CUB Director of Policy & Sr. Attorney Kristin Munsch, IL
OPUC Public Counsel Tonya Baer, TX

Legislators
NCSL President Senator Deb Peters, SD
NBCSL President Representative Greg Porter, IN
NHCSL Energy Task Force Member& Nevada President Pro Tempore, Senator Moises "Mo" Denis, NV
NBCSL Vice President Rep. Billy Mitchell, GA
NBCSL Energy/Trans/Env. Co-Chair Rep. Cherrish Pryor, IN
CSG Vice Chair Representative Helene Keeley, DE
NCSL Energy Supply TF Member Rep. Tom Sloan, KS
NBCSL Energy/Trans/Env. Co-Chair Rep. Angela Angel, MD
Chair Senate Energy and Public Utilities Committee Senator Mattie Hunter, IL
NCSL Past President Senator Curt Bramble, UT
Assemblyman Robin Schimminger, New York

Local Government
Mayor Jonathan F. Mitchell, New Bedford, MA; USCM Energy Chair
Mayor Elizabeth Kautz, Burnsville, MN; USCM Past President
NLC Executive Director Clarence Anthony
Mayor Toni Harp, New Haven, CT; President AAMA
Mayor Catherine Pugh, Baltimore, MD; USCM

Capital Markets
Daniel Ford, CFA, Managing Director, Head of North America Utilities Equity Research, Barclays

Powering the Future 2017

Sponsored by:

MACQUARIE

EY
Building a better working world

troutman sanders

Russell Reynolds ASSOCIATES

Itron

The Eau Palm
Manalapan, FL
October 7 - 10, 2017

DRAFT

Saturday, October 7, 2017

3:00 p.m. – 5:00 p.m.	**Registration**	*Ocean Ballroom Foyer*
5:00 p.m. –6:00 p.m.	**Women's Energy & Innovation Network (WeIN) Reception**	*Ocean Ballroom Foyer*
6:00 p.m. – 8:30 p.m.	**Women's Energy & Innovation Network (WeIN) Dinner**	*Ocean Ballroom*

Welcome
Susan Clark, Executive Director, WeIN

Dinner Dialogue: Connecting the Diversity & Inclusiveness Imperative to the C-Suite Agenda: A Leadership Dialogue
Diverse and inclusive leadership are essential for utilities and regulatory entities to navigate disruptive innovation. There is a well-documented body of evidence confirming the links between diversity and improved organizational performance, and a pervasive set of circumstances that indicate our industry has work to do to better reflect the communities, customers and constituencies we serve.

We are an industry that can be relied upon to connect people to the resources they need. When it comes to harnessing the power of diversity and inclusiveness, there appear to be disconnects that industry leaders must resolve. In this session, we will convene a panel of leaders to share insights on how their organizations have activated both D&I programs and individual leaders to address these disconnects.

Keynote Speaker:
FERC Commissioner Cheryl LaFleur

Lead Discussants:
Lisa Sparrow, President & CEO, Utilities, Inc.
Paula Glover, President & CEO, American Association of Blacks in Energy (AABE)
Anne Dailey, Partner, Troutman Sanders LLP
Jennifer Rockwood, Power & Utilities Practice Leader, Russell Reynolds Associates
Maya Smallwood, Principal, People Advisory Services, EY
Skye d'Almeida, Infrastructure Sponsor Coverage, Macquarie Capital (USA) Inc.

Sunday, October 8, 2017

7:00 a.m. – 10:30 a.m.	**WeIN Sunday Morning** Yoga/Breakfast *Sponsored by Troutman Sanders LLP*	*Beachside/Ocean Ballroom*
11:00 a.m. – 1:00 p.m.	**Registration**	*Plaza Ballroom Foyer*
1:00 p.m. – 1:05 p.m.	**Welcome** Wanyonyi Kendrick, Executive Director, EIPF	*Plaza Ballroom*
1:05 p.m. – 1:15 p.m.	**Opening Remarks** Alan James, Senior Managing Director, Macquarie Capital (USA) Inc.	*Plaza Ballroom*

1:15 p.m. – 3:10 p.m. **Discussion Session I: Utilities of the Future**
Policy makers and regulators are keenly focused on energy efficiency, water conservation, resource diversity, infrastructure investment, grid modernization and security. They also want stable, affordable and predictable rates. Many utility leaders are focused on the same goals. They are also focused on working more closely with their customers to respond to customers' specific needs. Meanwhile, for investor owned utilities revenue is based overwhelmingly on throughput. Utilities make money to attract capital and invest in service by selling more electricity, natural gas and water. How can these goals and the de facto business model be reconciled?

Moderator:
Alan James, Senior Managing Director, Macquarie Capital (USA) Inc.

Discussion Leader:
Robert C. Rowe, Director, President & CEO, NorthWestern Corporation

DRAFT

Federal Regulatory Perspective:
FERC Chairman Neil Chatterjee

Keynote Addresses:
Rolf Nordstrom, President & CEO, Great Plains Institute
Lisa Sparrow, President & CEO, Utilities, Inc.
James Kerr, Executive Vice President, General Counsel & Chief Compliance Officer, Southern Company
Dena Wiggins, President & CEO, Natural Gas Supply Association (NGSA)
Marisa Uchin, Head of Global Regulatory Affairs, Oracle Utilities

Wall Street:
Daniel Ford, CFA, Managing Director, Head of North America Utilities Equity Research, Barclays

Regulatory, Legislative & Consumer Perspectives:
NARUC Committee on Critical Infrastructure Co Vice-Chair and Commissioner Nick Wagner, IA
NARUC Electricity Co-Vice Chair and Commissioner John Rosales, IL
NARUC Taskforce on Innovation Chairman Brien Sheahan, IL
Chairman Brad Johnson, MT
NASUCA President Robert Nelson, MT

Open Discussion

3:10 p.m. – 3:25 p.m. **Refreshment Break** *Plaza Ballroom Foyer*

3:25 p.m. – 5:30 p.m. **Discussion Session II: The Digitalization of Our Communities**
The rapid development of technology is digitalizing our communities, altering physical (e.g. energy, water, waste, transportation) and social (e.g. social and economic inclusion, governance, citizen participation) infrastructures. Panelists will discuss the role and impact of the energy grid infrastructure in advancing Smart Cities and what we can expect for the future of smart communities.

Moderator:
Jennifer Rockwood, Power & Utilities Practice Leader, Russell Reynolds Associates

Industry Discussants:
Paula Gold-Williams, President & CEO, City Public Service (CPS Energy), San Antonio, TX
Benoit Laclau, Partner, Global Power & Utilities Leader, EY

Local Government Perspectives: Driving Smart Communities Forward
Mayor Jonathan F. Mitchell, New Bedford, MA; United States Conference of Mayors (USCM) Energy Chair
National League of Cities (NLC) Executive Director Clarence Anthony
Mayor Catherine Pugh, Baltimore, MD; United States Conference of Mayors (USCM)

Federal Regulatory Perspective:
FERC Director, Office of External Affairs, Leonard Tao

Regulatory, Legislative & Consumer Perspectives:
NARUC Task Force on Environmental Regulation and Generation Chairman Asim Haque, OH
Commissioner Maida Coleman, MO
NASUCA Vice President and Consumer Counsel Elin Swanson Katz, CT
NBCSL President and Representative Greg Porter, IN

Open Discussion: Q & A

5:30 p.m. **Adjourn**

6:00 p.m. – 7:00 p.m. **Welcome Reception** *Resort Lawn*

7:00 p.m. – 9:00 p.m. **Dinner & Dialogue**
Discussion Session III: Highlighting Smart Community Projects
Plaza Ballroom

DRAFT

Moderator:
Paul Roberti, Executive Director, Advisory Services- Strategy, EY

Keynote Speaker:
Pat Vincent-Collawn, Chairman, President & CEO, PNM Resources; Chairman, Edison Electric Institute (EEI)

Lead Discussants:
Mayor Toni Harp, New Haven, CT; President, African American Mayor's Association (AAMA)
Mayor Elizabeth Kautz, Burnsville, MN; United States Conference of Mayors (USCM) Past President
Councilmember Matt Zone, Cleveland, OH; President, National League of Cities (NLC)
Katrina McMurrian, Executive Director, Critical Consumer Issues Forum (CCIF)

Open Discussion: Q & A

Monday, October 9, 2017

7:00 a.m. – 7:45 a.m. **Breakfast** *Plaza Ballroom Foyer*

8:00 a.m. – 8:05a.m. **Welcome and Opening Remarks** *Plaza Ballroom*
Wanyonyi Kendrick, Executive Director, EIPF

8:05 a.m. – 9:15 a.m. **Discussion Session IV: Smarter Energy Infrastructure**
The energy grid provides tremendous value to all customers and businesses across the nation. It is the backbone of our economy and the electric system. Federal and state policymakers are adopting policies that recognize the value of the grid and the need to transform the grid to make it more resilient and smarter.

Moderator:
Jennifer Rockwood, Power & Utilities Practice Leader, Russell Reynolds Associates

Setting the Stage to the Smart City Revolution
Philip Mezey, President & CEO, ITRON

Keynote Address: Vision of the Future
Pat Vincent-Collawn, Chairman, President & CEO, PNM Resources; Chairman, Edison Electric Institute (EEI)

Smart Grid Solutions Open Roundtable Discussion
Pat Vincent-Collawn, Chairman, President & CEO, PNM Resources; Chairman, Edison Electric Institute (EEI)
Philip Mezey, President & CEO, ITRON
Lloyd Yates, EVP, Customer and Delivery Operations and President, Duke Energy's Carolinas Region
Mike Rowe, Chairman, President & CEO, American Transmission Co.

Open Discussion: Q&A

9:15 a.m. - 10:45 a.m. **Discussion Session V: CEO Roundtable**
Speakers will highlight innovation, infrastructure, investment, and customer experience in the age of technology. Participants will also discuss the implications of innovative technologies on energy in the digital age.

Moderator:
Susan Bell, Partner, Power & Utilities Leader for America's Financial Acct. Advisory Services, EY

Federal Regulatory Perspective:
FERC Chairman Neil Chatterjee

Keynote Addresses:
Armando Pimentel, President& CEO, NextEra Energy Resources LLC
Susan N. Story, Director, President & CEO, American Water Works Company, Inc.
Linda Blair Apsey, President & CEO, ITC Holdings Corp.
Kimberly S. (Kim) Greene, Executive Vice President and Chief Operating Officer, Southern Company
Calvin G. Butler Jr., CEO, Baltimore Gas and Electric Company (BGE)
Mary E. Kipp, Director, President & CEO, El Paso Electric Company

DRAFT

Regulatory, Legislative & Consumer Perspectives:
NARUC First Vice President and Chairperson Ellen Nowak, WI
NASUCA Electricity Chair Robert Mork, IN
NARUC Chair Committee on Energy Resources and the Environment Chair Nancy Lange, MN
Commissioner Nikiya "Nikki" Hall, SC
NCSL President and Senator Deb Peters, SD
NHCSL Energy Task Force Member & Nevada President Pro Tempore, Senator Moises "Mo" Denis, NV
NBCSL Energy, Transportation & Environment Co-Chair Representative Angela Angel, MD

Open Discussion: Q & A

10:45 a.m. – 11:00 a.m. Break

11:00 a.m. – 11:30 a.m. **Discussion Session VI: A New Path for Cleaner Energy**
To provide safe, reliable, affordable and clean energy to their customers and minimize their impact on the environment, utilities must use more natural gas – which can play a leading role as a baseload alternative to coal and a supporting role as a complement to renewables. Transporting more natural gas to regions once heavily reliant on coal to generate electricity requires additional – and timely – infrastructure. This session will explore the process to permit pipelines, while preserving and protecting important historic, cultural and natural resources.
.

Moderator:
Eric Weng, Managing Director, Macquarie Capital (USA) Inc.

Keynote Address:
Thomas F. Farrell, II, Chairman, President & CEO, Dominion Energy, Inc.

Open Discussion: Q & A

11:30 a.m. – 1:00 p.m. **Discussion Session VII: The "Evolving" Generation Portfolio**
The generation portfolio is clearly evolving. Recent advancements in both distributed and demand side or resources are creating a new set of challenges/opportunities in transmission planning, interconnection, operations, and market products; heightening the focus on the effectiveness of current economic regulation. Panelists will discuss how all the pieces fit together to define the future of integrated power systems and how they can be operated reliably and efficiently.

Moderator:
Paul Roberti, Executive Director, Advisory Services- Strategy, EY

Federal Regulatory Perspective:
FERC Commissioner Cheryl LaFleur

Keynote Addresses:
Gregg Rotenberg, President & CEO, Smart Wires, Inc.
Kimberly S. (Kim) Greene, Executive Vice President and Chief Operating Officer, Southern Company
Clair J. Moeller, Executive Vice President, Operations, MISO
Krista Tanner, President, ITC Midwest
Charles Patton, Executive Vice President – External Affairs, American Electric Power

Regulatory, Legislative & Consumer Perspectives:
Chairman Sandy Jones, NM
Commissioner Kimberly Lindsey O'Guinn, AR
Commissioner Dr. Talina Mathews, KY
Commissioner Michael Huebsch, WI
CUB Director of Policy & Sr. Attorney Kristin Munsch, IL
NCSL Energy Supply Task Force Member and Representative Tom Sloan, KS

Open Discussion: Q & A

1:15 p.m. - 2:30 p.m. **Lunch** *Ocean Ballroom & Terrace*

DRAFT

Discussion Session VIII: Expanding Roles for Legal Counsel
With uncertain global markets, cybersecurity issues and increasing regulatory demands, obstacles to business success have never appeared larger, and corporate legal teams have never played a bigger role. As general counsel and other corporate attorneys move beyond focusing strictly on law-related duties, expanding their scope of influence to overall business affairs, the need for nimble, multi-talented, business-minded legal departments rises. How do legal teams help their companies succeed despite these changing conditions? Three skilled industry leaders share their formulas for success.

Moderator:
Steven J. Hewitson, Partner, Troutman Sanders LLP

Lead Discussants:
Leila Vespoli, EVP, Corporate Strategy, Regulatory Affairs, and Chief Legal Officer, FirstEnergy Corp.
Julie S. Janson, Executive Vice President, External Affairs, Chief Legal Officer and Corporate Secretary, Duke Energy
Carlos M. Brown, Vice President and General Counsel, Dominion Energy, Inc.

Regulatory, Legislative & Consumer Perspectives:
NARUC Water Committee Chair and Commissioner Mary-Anna Holden, NJ
NARUC Gas Committee Chair and Chairman Stan Wise, GA
Vice Chair Cynthia Hall, NM
Commissioner Bob Anthony, OK

2:45 p.m. – 5:30 p.m. **Group Breakout Sessions:** Discussion groups will review the morning and afternoon sessions and formulate position statements for resolution of the issues discussed. Participants will also discuss conservation and energy.

2:45 p.m. – 3:30 p.m. **POWER UP (OPTIONAL)** *Plaza Ballroom*
An interactive session focused on projecting confidence, widening networks, elevating communication and realizing purpose.

Moderator:
Susan Bell, Partner, Power & Utilities Leader for America's Financial Acct. Advisory Services, EY

Discussion Leader:
Paul Roberti, Executive Director, Advisory Services- Strategy, EY
Gayle Lanier, SVP, Customer Services, Duke Energy
Michele Wheeler, VP Regulatory & Political Affairs, NextEra Energy Resources
Anne George, Vice President, External Affairs and Corporate Communications, ISO-NE

6:00 p.m. – 7:00 p.m. **Reception** *Courtyard Pool*

7:00 p.m. - 9:00 p.m. **Dinner & Dialogue** *Ocean Ballroom & Terrace*

Tuesday, October 10, 2017

7:00 a.m. – 7:45 a.m. **Continental Breakfast** *Plaza Ballroom Foyer*

8:00 a.m. - 8:05 a.m. **Welcome** *Plaza Ballroom*

8:05 a.m. - 9:15 a.m. **Discussion Session IX: State Policy and Competitive Wholesale Markets: Issues and Solutions**
Panelists will focus on defining the issues and suggesting solutions regarding state policies that support selected generation resources participating in the wholesale competitive energy markets. What policy goals do states seek to accomplish – jobs retention or creation, environmental benefits, etc.? Do such policies conflict with the goals of a competitive wholesale energy market? How can conflicts be addressed to both retain the benefits of the wholesale market and accomplish state policy goals?

Moderator:
Dan Pfeiffer, Vice President Governmental Affairs, Itron, Inc.

DRAFT

Industry Discussants:
Frederick S. Bresler, III, Senior Vice President - Operations and Markets, PJM Interconnection
Anne George, Vice President, External Affairs and Corporate Communications, ISO-NE
Tanya Paslawski, Executive Director, Organization of MISO States
Mary Pietrzyk, Senior Manager, Policy Development, Nuclear Energy Institute (NEI)

Regulatory, Legislative & Consumer Perspectives:
NARUC Sub on Supplier & Workforce Development Chair and Commissioner Sherina Maye Edwards, IL
Vice Chairman Robert Cicero, KY
Acting Commissioner Sadzi Oliva, IL
NASUCA Secretary and Director of Consumer Advocate Division Jackie Roberts, WV
NCSL Past President Senator Curt Bramble, UT

Open Discussion: Q & A

9:15 a.m. - 10:30 a.m. **Discussion Session X: Preparing for Natural Disasters and Protecting Customers from Deceptive Behaviors**
Speakers will discuss how local, state and federal policymakers, as well as industry and consumers can prepare themselves in a natural disaster. This interactive discussion will identify lessons learned from Hurricane Irma, Harvey, Sandy and others. It will also provide "best practices" for avoiding relief scams, robo-calls, and price gouging during a time when protections are not readily available.

Moderator:
Marc Baca, Executive Director, Russell Reynolds Associates

Roundtable Discussants:
Janet Sena, Senior Vice President and Director of Policy and External Affairs, NERC
Sheri Givens, President, Givens Consulting, LLC
NBCSL Vice President Representative Billy Mitchell, GA
NARUC Subcommittee on Education & Research Chair John "Butch" Howard, SC
CUB Executive Director David Kolata, IL
OPUC Public Counsel Tonya Baer, TX
Council of State Governments (CSG) Vice Chair and Representative Helene Keeley, DE
Chair Senate Energy and Public Utilities Committee Senator Mattie Hunter, IL

Open Discussion: Q & A

10:30 a.m. – 10:45 a.m. **Refreshment Break** *Plaza Ballroom Foyer*

10:45 a.m. – 12:15 p.m. **Discussion Session XI: New Direction on Environmental Policy Under the Trump Administration**
Panelists will discuss significant changes in environmental policy under the Trump Administration that will impact regulated utilities, with a focus on the long-anticipated repeal of the Clean Power Plan, regulating CO2 emissions from power plants, and the potential for a federal replacement rule. The panel will also discuss how the change in federal policy may play out at the state level, with some states electing to move forward with their own version of the regulations.

Moderator:
Margaret Claiborne Campbell, Partner, Troutman Sanders LLP

Lead Discussants:
Alexandra Dapolito Dunn, Executive Director & General Counsel, Environmental Council of the States (ECOS)-American College of Environmental Lawyers (ACOEL)
Mandy Gunasekara, Senior Policy Advisor, US Environmental Protection Agency (EPA)
Melissa Horton, Federal Environmental Affairs, Southern Company

Regulatory, Legislative & Consumer Perspectives:
NBCSL Energy, Transportation & Environment Co-Chair and Representative Cherrish Pryor, IN
NARUC Water Co-Vice Chair and Commissioner Comer "Randy" Randall, SC
NARUC Nuclear Issues/ Waste Disposal Sub Vice-Chair and Commissioner Lauren "Bubba" McDonald, Jr. GA

DRAFT

	Commissioner Stephen M. Stoll, MO Commissioner Jordan White, UT Assemblyman Robin Schimminger, NY	
12:15 – 12:30 p.m.	**Closing Remarks** Wanyonyi Kendrick, Executive Director, EIPF	
12:30 p.m.	**Adjourn**	
12:35 p.m.	**Lunch**	*Ocean Ballroom & Terrace*

DRAFT

Meeting with Alliance/Global Automakers

Powertrain efficiency in EPA's technical assessment to-date, and plans for ongoing updates

September 21, 2017
Office of Transportation and Air Quality
National Vehicle and Fuel Emissions Laboratory

High-level Summary of Alliance comments based on Novation Analytics review of 2016 EPA powertrain modeling

Alliance comment 1

LPM does not account for engine operating load over the test cycles, and therefore incorrectly projects technology effectiveness when operating loads differ from the exemplar vehicles'

Alliance comment 2

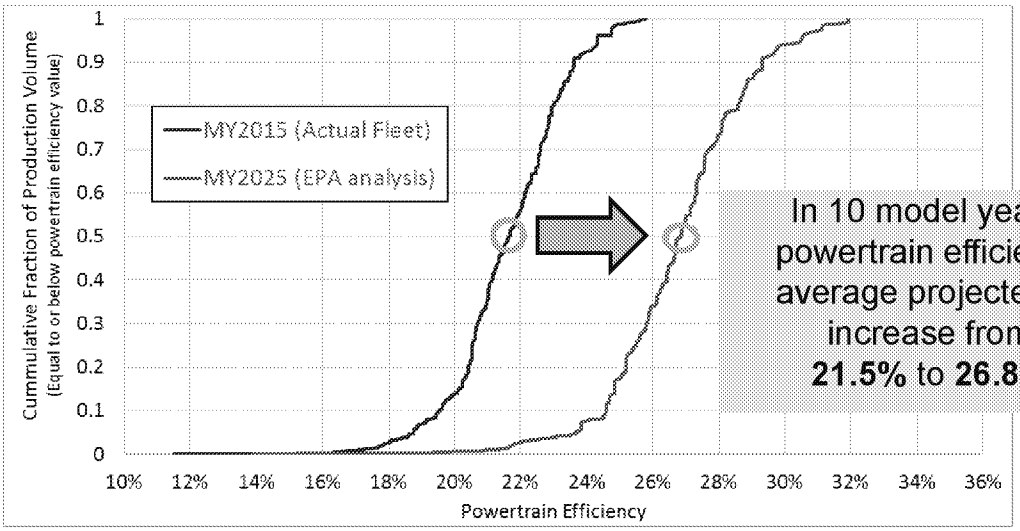
LPM outputs should be screened using energy efficiency metrics

Alliance comment 3

Recent rate of powertrain efficiency improvement is not sufficient to meet MY2025 GHG standards

Review of EPA's 2016 PD Results using Powertrain Efficiency Metrics

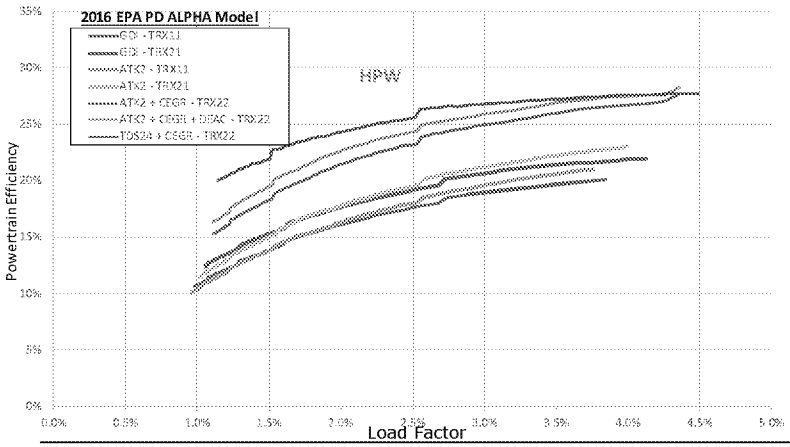
2016 EPA Proposed Determination: Baseline vs. Future Gasoline Powertrain Efficiency



In 10 model years, powertrain efficiency average projected to increase from **21.5%** to **26.8%**

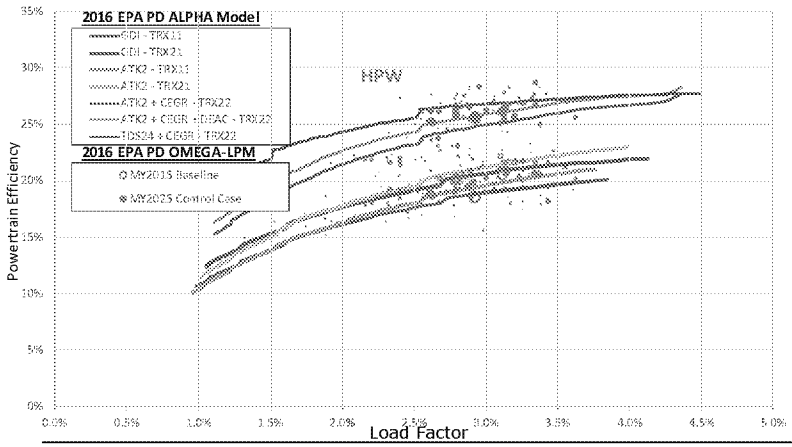
2016 EPA Proposed Determination: Accounting for Operating Load in ALPHA and LPM

- ALPHA model results project lower powertrain efficiencies as the ratio of operating load to engine power decreases



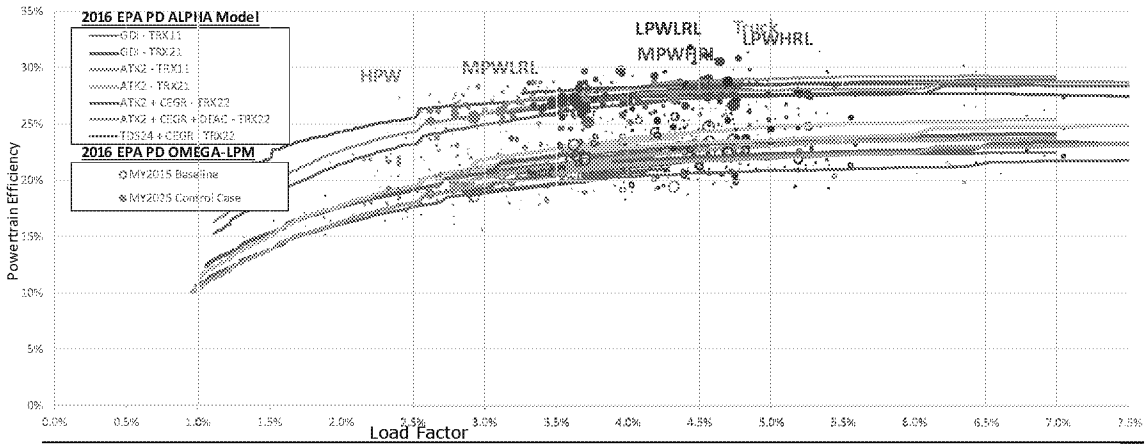
2016 EPA Proposed Determination: Accounting for Operating Load in ALPHA and LPM

- ALPHA model results project lower powertrain efficiencies as the ratio of operating load to engine power decreases
- OMEGA-LPM effectiveness values for MY2025 packages are generally within the bounds of powertrain efficiencies modeled in ALPHA
  - Small proportion of vehicles exceed ALPHA modeled powertrain efficiencies due to baseline technology characterization and road load coefficients and emissions values reported by certification test group.



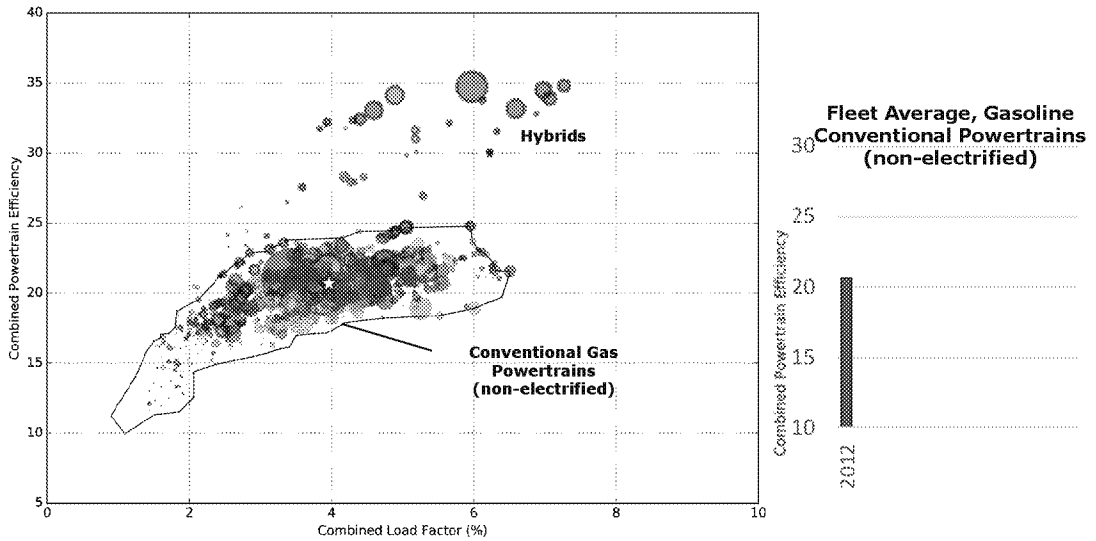
2016 EPA Proposed Determination: Accounting for Operating Load in ALPHA and LPM

- ALPHA model results project lower powertrain efficiencies as the ratio of operating load to engine power decreases
- OMEGA-LPM effectiveness values for MY2025 packages are generally within the bounds of powertrain efficiencies modeled in ALPHA
  - Small proportion of vehicles exceed ALPHA modeled powertrain efficiencies due to baseline technology characterization and road load coefficients and emissions values reported by certification test group.
- The same findings apply across all six ALPHA classes

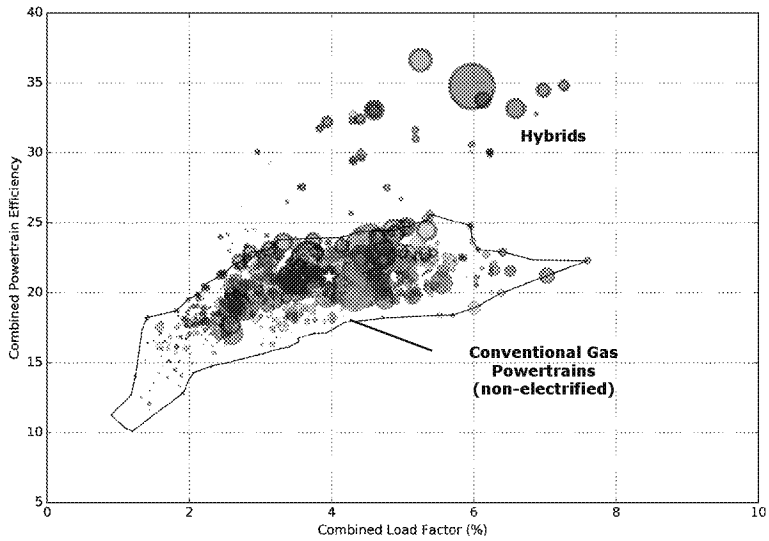


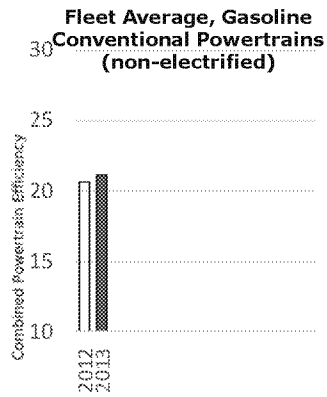
Fleet Powertrain Efficiency 2012-2016

Distribution of Fleet Powertrain Efficiencies MY2012

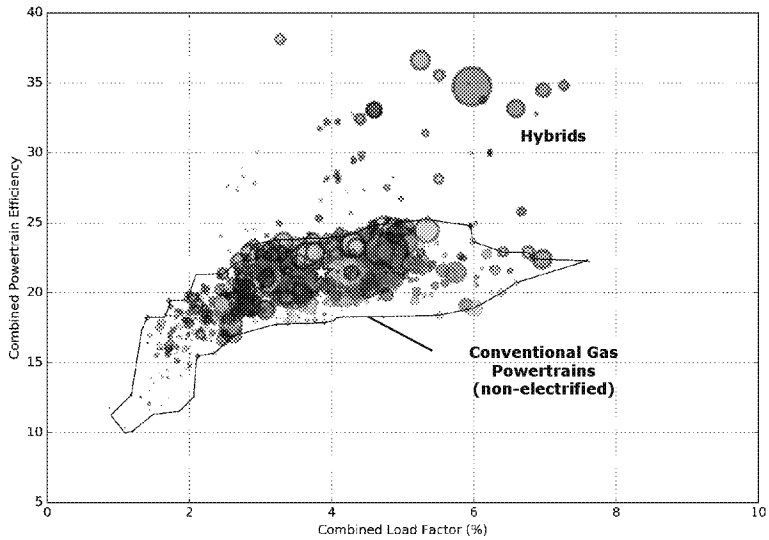


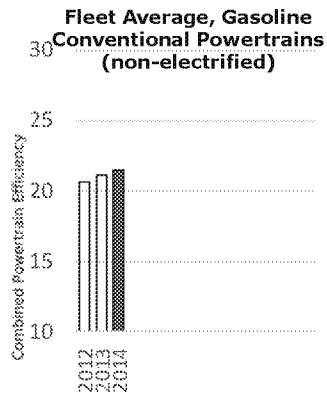
Distribution of Fleet Powertrain Efficiencies MY2013



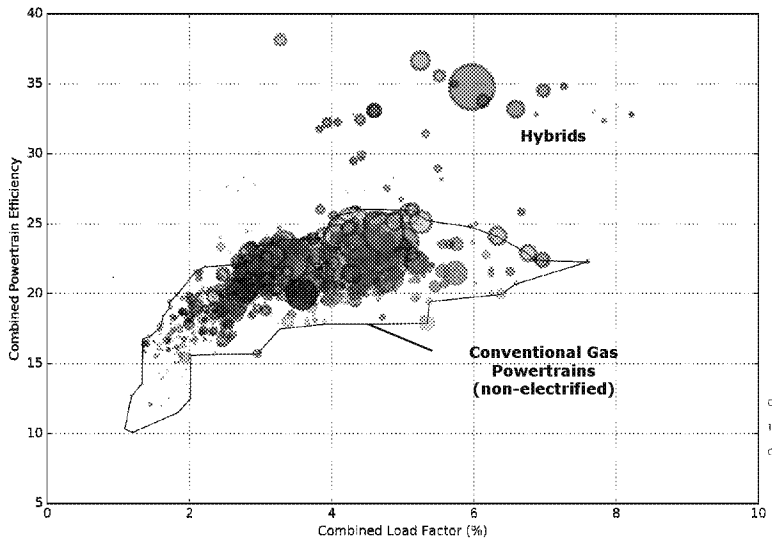


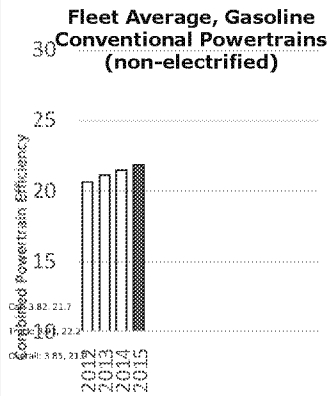
Distribution of Fleet Powertrain Efficiencies MY2014



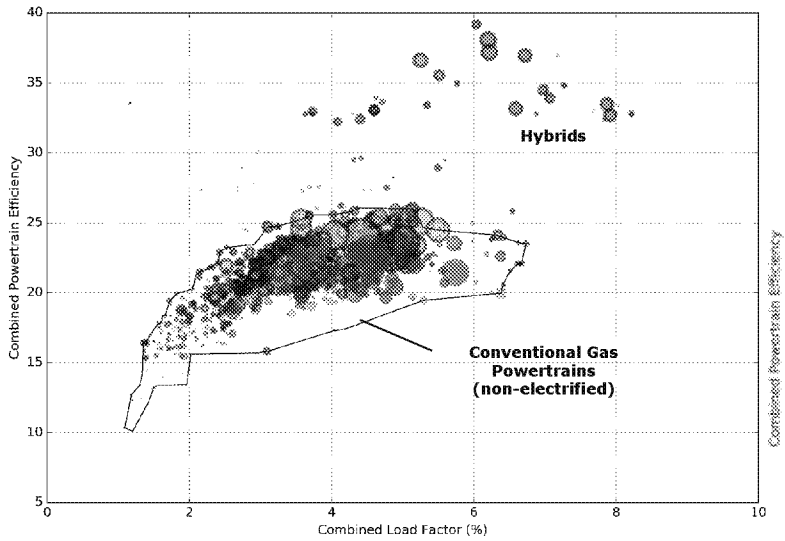


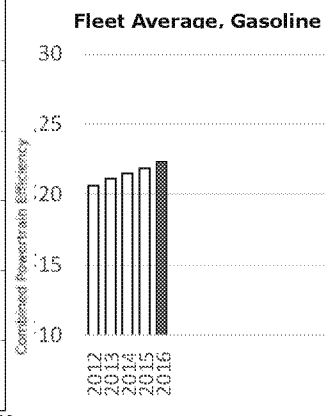
Distribution of Fleet Powertrain Efficiencies MY2015





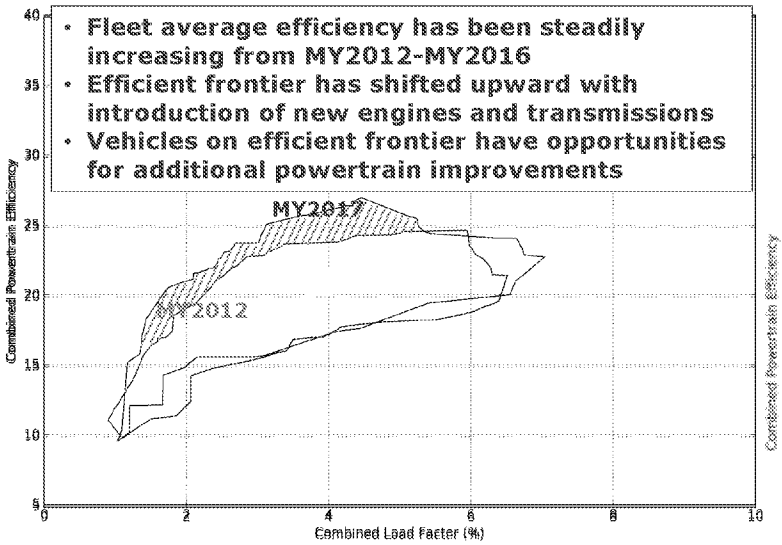
Distribution of Fleet Powertrain Efficiencies MY2016

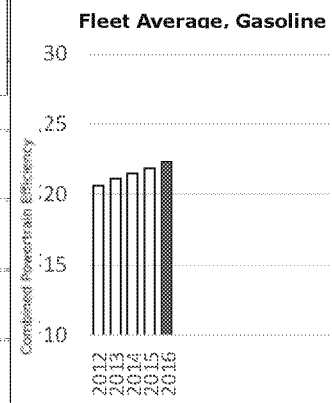




Rate of Improvement in Fleet Powertrain Efficiencies MYs 2012 - 2016

- Fleet average efficiency has been steadily increasing from MY2012-MY2016
- Efficient frontier has shifted upward with introduction of new engines and transmissions
- Vehicles on efficient frontier have opportunities for additional powertrain improvements





Current Work on Incorporating ALPHA results into OMEGA

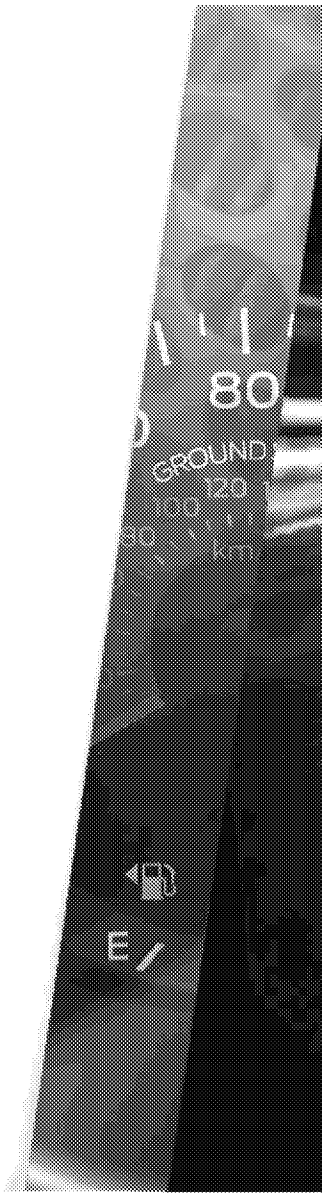
Ongoing MTE updates to EPA's Modeling Process for Technology Effectiveness

- **Stakeholders submitted comments for the Draft TAR and PD on the Lumped Parameter Model (LPM), including:**
  - Lack of transparency in the calibration of the LPM
  - Recommendation to incorporate ALPHA results more directly into OMEGA
- **EPA has initiated the peer review process of a revised methodology for integrating ALPHA modeling results into the OMEGA fleet compliance model**
  - Ongoing expansion of technology library and computational improvements enable direct ALPHA simulation for each of the ~1300 vehicles in the baseline fleet
  - Computational improvements allow full factorial modeling of future technology combinations
  - Full factorial modeling allows an automatic calibration of response surface equations for multiple future technology combinations, where the underlying data are directly tied to outputs from ALPHA full vehicle modeling.
- **The revised fleet compliance modeling methodology would be substantially similar to the previous methodology, but with a set of auto-calibrated response surface equations taking the place of the LPM.**

novation
analytics
80
GROUND SPEED
120 140
100
160
km/h
E

EPA Mid-Term Evaluation Technical Briefing

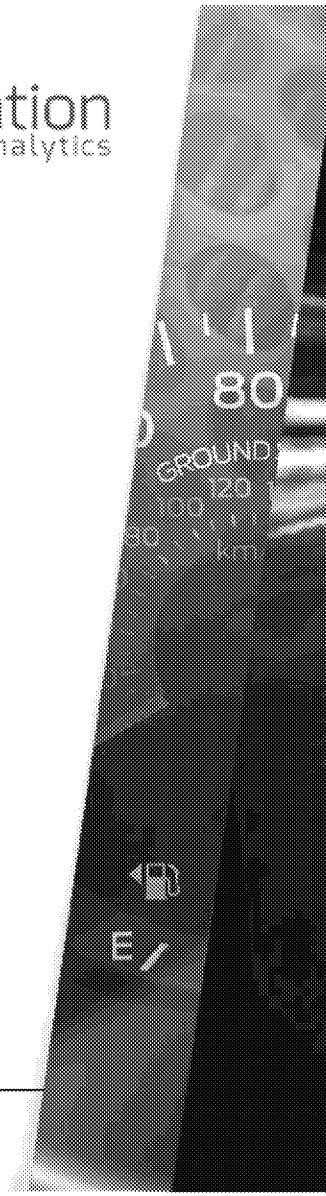
September 2017



Disclaimer

novation analytics

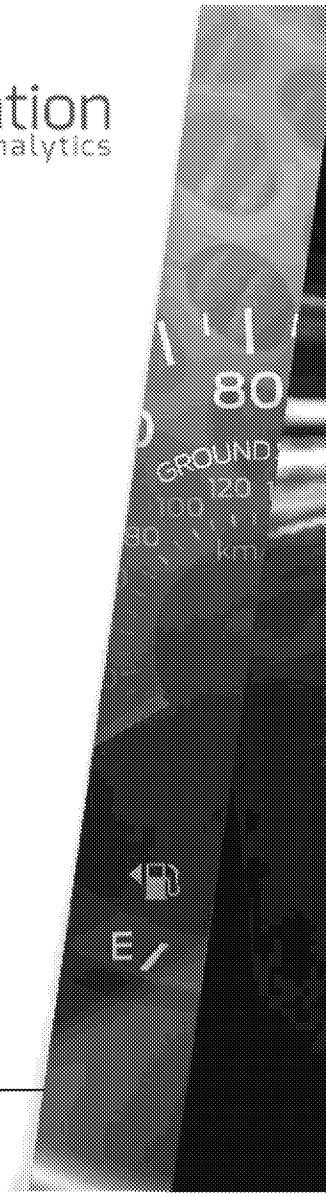
The statements and conclusions in this document are those of Novation Analytics, LLC and not those of the Alliance of Automobile Manufacturers, the Association of Global Automakers, or its members.



Contents

novation analytics

- Summary of Prior Studies Regarding the EPA CO_2 Projection Process
- EPA's Response to Prior Studies
- EPA's CO_2 Projection Process
- Assessment of EPA's Process Changes for the Final Determination
- Novation's Assessment of ALPHA-to-OMEGA Bias
- Conclusions & Recommendations



novation analytics

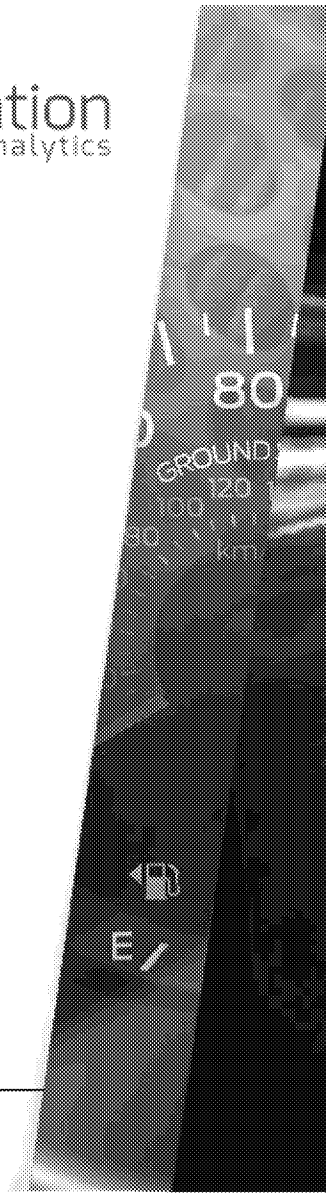
Summary of Prior Studies Regarding the EPA CO_2 Projection Process

Key Conclusions from Prior Studies

novation analytics

Assessment of the FRM fuel economy and tailpipe CO_2 emissions results yielded two particular areas of concern:

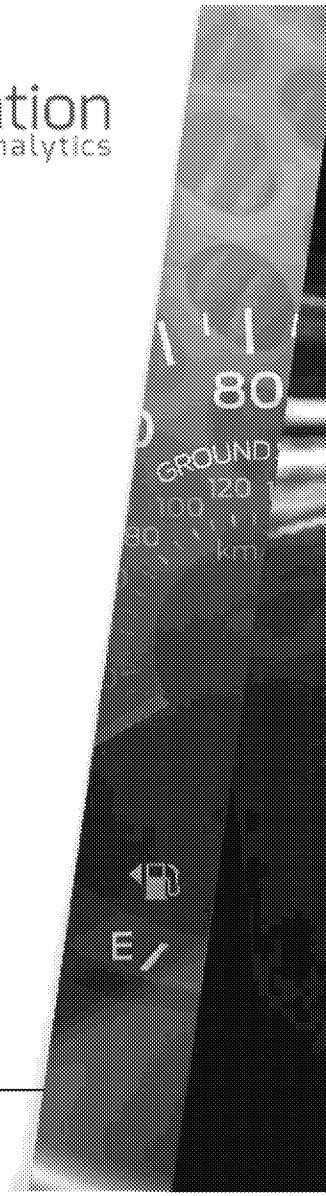
1. The Lumped Parameter Model (LPM) has fundamental deficiencies that cause under-projection of tailpipe CO_2 for individual vehicles. In particular, the LPM does not utilize engine displacement or tractive energy as inputs.
2. The Ricardo modeling results used to calibrate the LPM for the FRM fail basic plausibility checks.

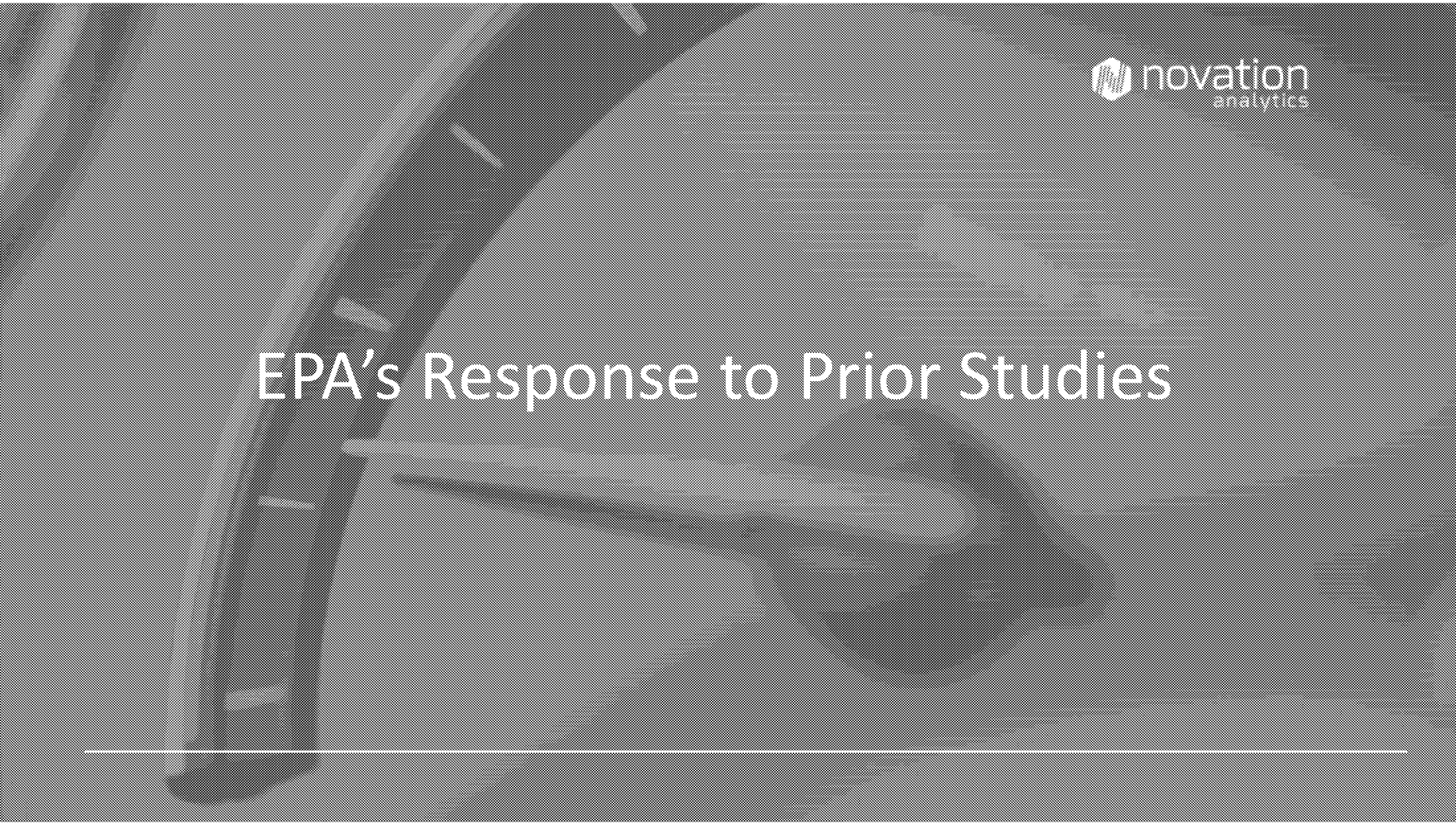


Recommendations from Prior Studies

novation analytics

- Utilize powertrain efficiency to assess the plausibility and sustainability of vehicle modeling results.
- Upgrade the LPM or replace it with another modeling method.
- Remove the Ricardo modeling results from the mid-term evaluation (MTE) analyses.





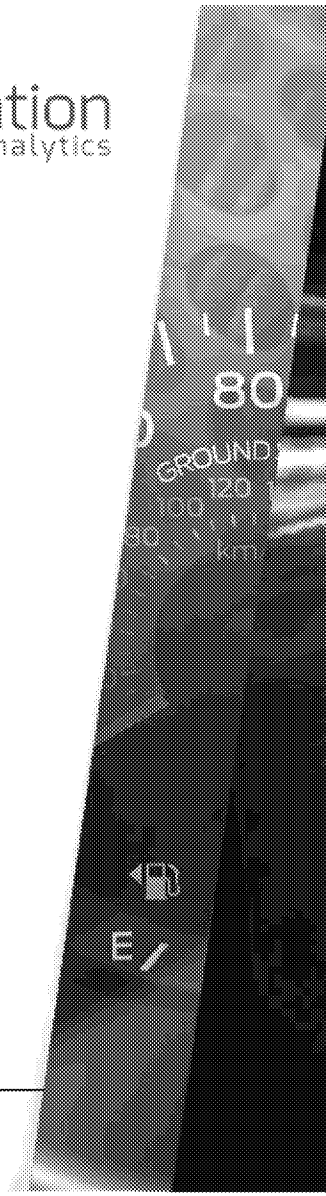
EPA's Response to Prior Studies

EPA's Response to Recommendations

novation analytics

Positive Outcomes:

- EPA adopted Novation's conversion efficiency and tractive energy metrics.
- EPA is making greater use of ALPHA-based full vehicle simulations to supersede questionable Ricardo-based simulations.
- EPA recognizes displacement-specific load as an important determinant of technology effectiveness and powertrain efficiency.



EPA's Response to Recommendations

novation analytics

Ongoing Concerns:

- EPA's use of the conversion efficiency metric is only as a measurement/observation tool, not as a quality control (accept/reject) tool.
- The basic structure of the LPM did not change and, therefore, EPA did not address the under projection of CO_2 by the LPM.
- EPA's update of the LPM does not include engine displacement specific load, instead incorrectly applies power-to-weight as a surrogate.
- EPA has not provided detail of their process to generate the LPM model coefficients.
- The technologies modeled by ALPHA published results only represent 18% of EPA's final compliance fleet; meaning that 82% of the CO_2 projections in the final determination are based on other sources of data.

EPA's CO_2 Projection Process

Why is EPA Using the LPM?

novation analytics

From section 5.3.3.4 of the Draft TAR:

"*It is widely acknowledged that full-scale physics-based vehicle simulation modeling is the most thorough approach for estimating future benefits of a package of new technologies … However, developing and executing every possible combinations of technologies directly in a fleet compliance model using full scale vehicle simulation would not be practical to implement.*"

"*The lumped parameter approach was again chosen as the most practical surrogate to estimate the effectiveness of the technology package combinations for the Draft TAR analysis.*"

Novation's Interpretation: The CO_2 values from OMEGA are not, directly, the results of full-scale (1-D) vehicle simulations (e.g., ALPHA); rather, they were generated by a simple 0-D model (LPM).

Why is EPA Using the LPM?

novation analytics

Recognizing the limitations of the LPM approach, EPA acknowledged that its results may be over or underestimated. From Appendix A of the Proposed Determination TSD:

> *"The EPA acknowledges that this modeling process is a simplification, as are all models, and mapping different vehicles in the baseline fleet to the same exemplar will produce both small over-estimates and small under-estimates of technology effectiveness, depending on how close the baseline vehicle is to the exemplar used in the LPM. However, on a fleet-wide average, these small over-and under-estimates of technology effectiveness tend to average out."*

Novation's Interpretation: As a surrogate to full-scale simulation (i.e., ALPHA) the LPM should provide, on average, equivalent CO_2 levels for the group of vehicle being evaluated.

ALPHA Technology Coverage

novation analytics

- Published ALPHA results only cover a subset of the powertrain technologies in the OMEGA MY 2025 pathway (~18% of the fleet).
- Other significant segments not covered by published ALPHA results include SI port injection and 18 bar BMEP turbocharging (together ~39% of the fleet).

Powertrain Type	Engine Technology	EGR	Fuel System	Cyl. Deac.	Stop-Start	Trans.	% of MY 2025 OMEGA Fleet	ALPHA Simulations Available?
SI	Atkinson @ 13:1 CR		Direct	yes		ATX	1.3%	
SI	Atkinson @ 13:1 CR		Direct			ATX	0.7%	yes
SI	Atkinson @ 14:1 CR	cooled	Direct	yes		ATX	14.1%	yes
SI	24 bar BMEP TC	cooled	Direct			ATX	0.6%	yes
SI	Nat. Asp.		Direct			ATX	2.9%	yes
SI	Nat. Asp.		Direct	yes		ATX	0.6%	
SI	Nat. Asp.		Port			ATX	4.6%	
SI	Nat. Asp.	cooled	Port			ATX	2.4%	
SI	Nat. Asp.		Port	yes		ATX	13.2%	
SI	18 bar BMEP TC		Direct			ATX	19.0%	
SI	18 bar BMEP TC	cooled	Direct			ATX	0.1%	
SI	Atkinson @ 13:1 CR		Direct	yes	yes	ATX	0.7%	
SI	Atkinson @ 13:1 CR		Direct		yes	ATX	-	
SI	Atkinson @ 14:1 CR	cooled	Direct	yes	yes	ATX	5.9%	
SI	24 bar BMEP TC	cooled	Direct		yes	ATX	1.5%	
SI	Nat. Asp.		Direct		yes	ATX	0.3%	
SI	Nat. Asp.		Direct	yes	yes	ATX	1.0%	
SI	Nat. Asp.		Port		yes	ATX	-	
SI	Nat. Asp.	cooled	Port		yes	ATX	-	
SI	Nat. Asp.		Port	yes	yes	ATX	1.6%	
SI	18 bar BMEP TC		Direct		yes	ATX	4.0%	
SI	18 bar BMEP TC	cooled	Direct		yes	ATX	-	
SI	18 bar BMEP TC	cooled	Direct	yes	yes	ATX	0.0%	
SI	Miller Cycle	cooled	Direct	yes	yes	ATX	0.2%	
SI-E	Mild Hybrid						17.6%	
SI-E	Strong Hybrid						2.2%	
Other							5.5%	

Coverage of the MY 2025 OMEGA Projected Fleet (central case, primary analysis) with ALPHA Full-Vehicle Simulation Data

Key Takeaway: Only 18% of EPA's MY 2025 pathway was informed (indirectly through the LPM) by the published ALPHA full-vehicle simulations.

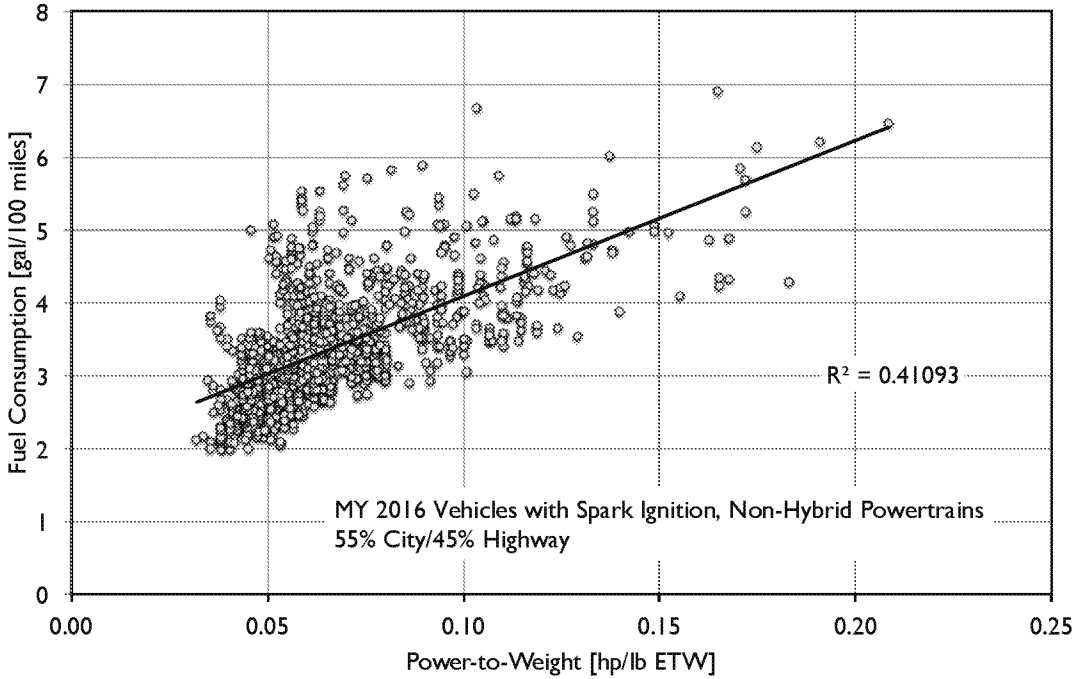
novation analytics

Assessment of EPA's Process Changes for the Final Determination

EPA's Use of Power-to-Weight

novation analytics

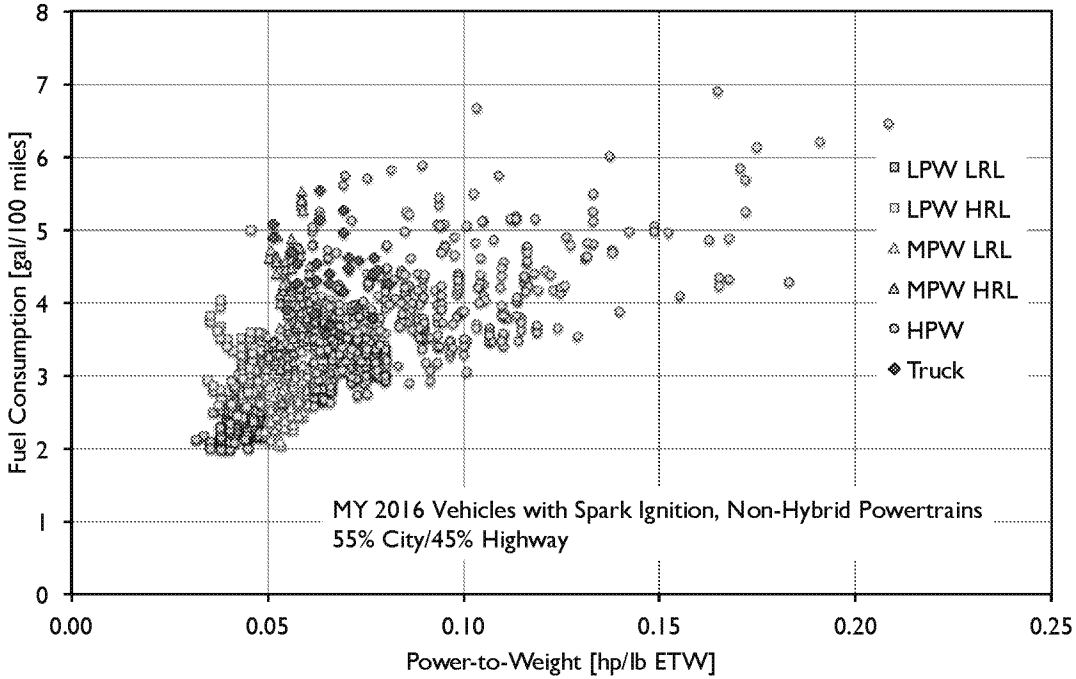
- EPA attempted to address the LPM's lack of engine displacement specific load by using power and weight as surrogates for engine displacement and tractive load, respectively.
- However, power is not a robust substitute for engine displacement due to the wide range of specific power from engine configurations and features.
- Additionally, weight does not fully capture tractive energy.
- Power-to-weight accounts for only 41% of the variation in fuel consumption (and CO2 emissions) across the vehicle fleet.



EPA's Use of Power-to-Weight

novation analytics

- The EPA categorized vehicles by power-to-weight class and road load horsepower.
- While the categorization captures some of the additional variation, the overall correlation remains weak.

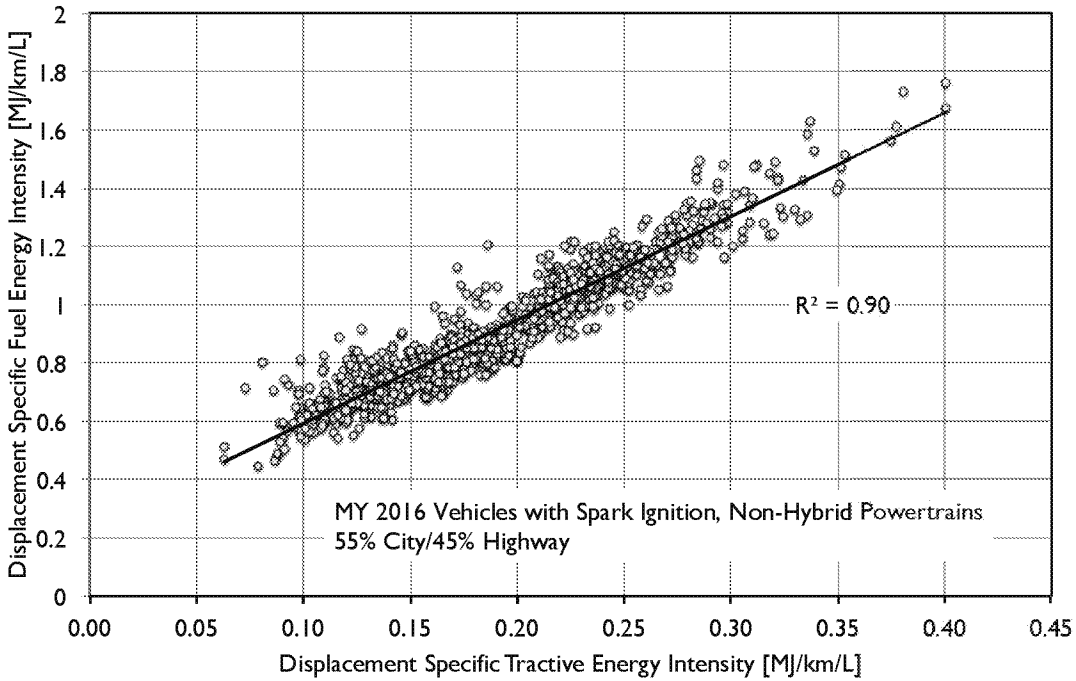


Key Takeaway: EPA's use of power-to-weight ratio as a surrogate for displacement specific operating load is not fundamentally correct nor robust.

Displacement-Specific Energy Domain

novation analytics

- As noted in Novation's earlier studies, displacement-specific tractive energy can be used as a surrogate for brake mean effective pressure (BMEP), a widely recognized measure of engine operating load.
- For internal combustion engines, displacement-specific fuel consumption is linearly correlated to displacement specific load and accounts for 90% of the variation in fuel consumption across the vehicle fleet.

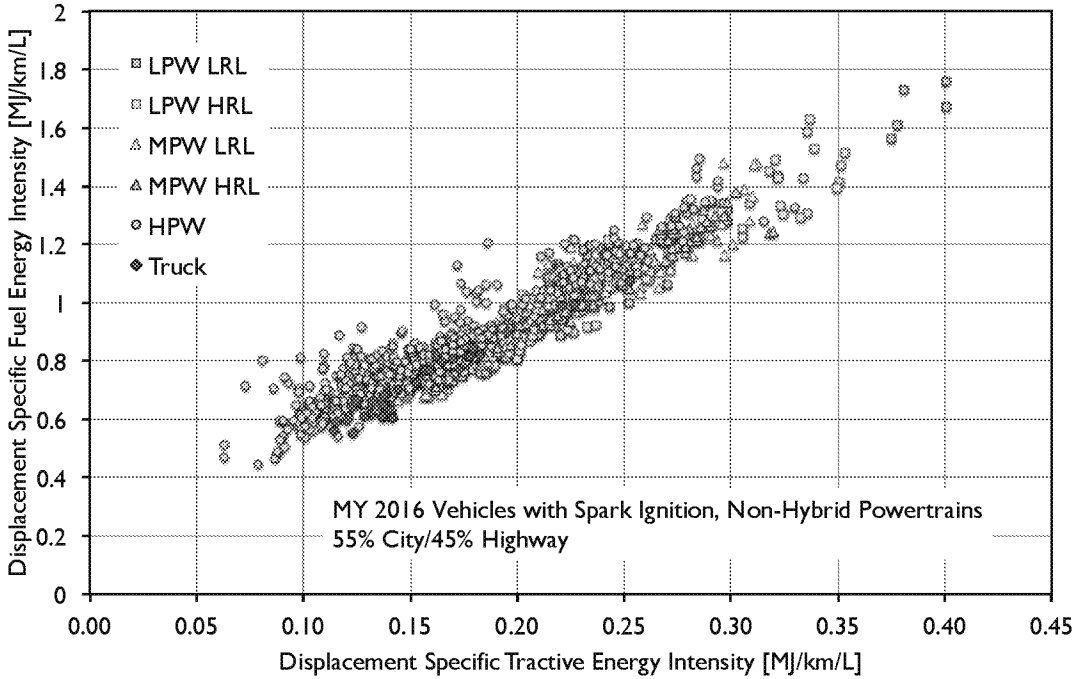


Key Takeaway: Displacement specific energy domain provides a significantly higher correlation than power-to-weight ratio.

Displacement-Specific Energy Domain

novation analytics

- Applying EPA's updated LPM vehicle categories yields significant overlap in the displacement specific operating domain.
- Application of technologies for vehicles operating at the same displacement specific operating load will yield similar results.
- However, given the significant overlap, the EPA LPM process incorrectly applies different technology effectiveness values for vehicles in the same operating domain.



Key Takeaway: EPA's LPM categories overlap in the displacement specific operation load domain; therefore EPA is incorrectly applying technology adjustments to many vehicles.

EPA's ALPHA-to-LPM Bias Assessment

novation analytics

- To address the concern of CO_2 under-projection, EPA's Figure 2.100 in the PD TSD purports to show that a comparison of LPM and ALPHA modeled effectiveness values for a broad range of vehicles is within 2%.
- However, EPA's ALPHA results used for this figure are not bona fide full-vehicle simulation results for the 36 specific vehicles listed for this comparison.
  - Only 4 generic engine maps were used to represent all vehicles shown.
  - Baseline engine displacement was often inconsistent with the actual vehicle's MY 2015 displacement.

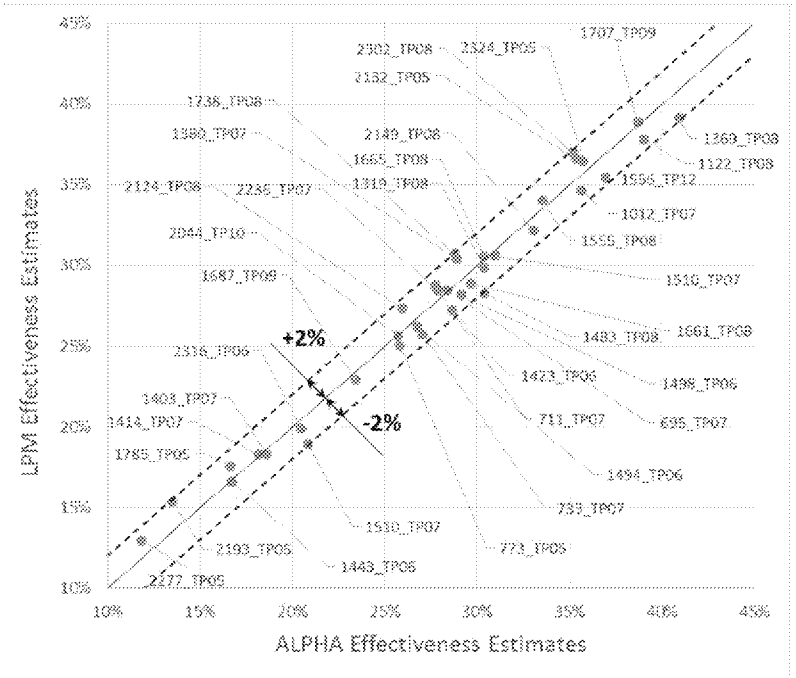


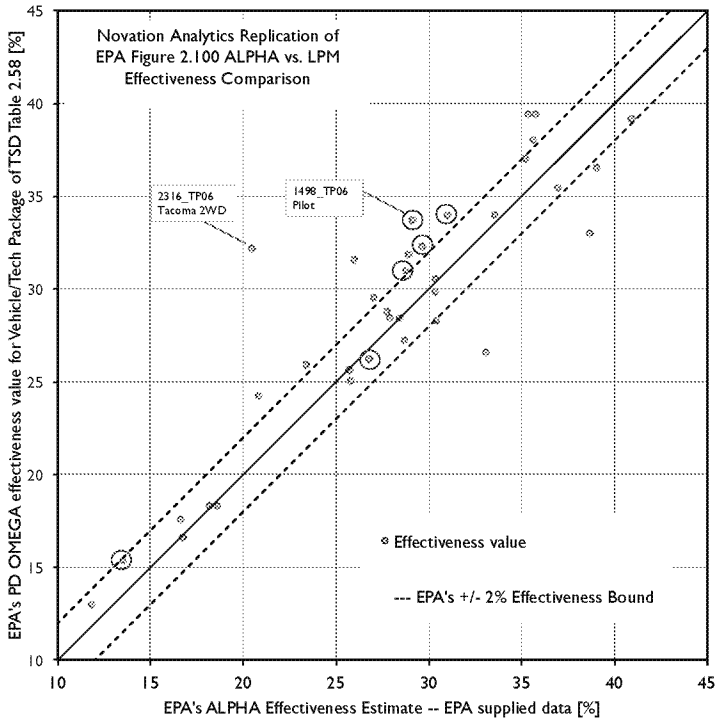
Figure 2.100 LPM and ALPHA Package Effectiveness Comparison for Vehicles and Throughout Distribution of Powertrain Efficiencies (TSD pg. 2-286)

Key Takeaway: The ALPHA simulations do not represent MY 2015 production vehicles as implied by the Proposed Determination (TSD section 2.3.3.5.4, page 2-286).

EPA's ALPHA-to-LPM Bias Assessment

novation analytics

- Novation attempted to replicate EPA's Figure 2.100 using ALPHA results provided by EPA and the OMEGA output detail of the 36 vehicles identified in TSD Table 2.58.
- Most vehicles identified in Table 2.58 had different end state Tech Packages than were modeled by EPA using ALPHA. Only 6 vehicles, circled in red, matched end state Tech Packages in both model sets.
- The results for 17 of the 36 vehicles fall outside EPA's 2% effectiveness bound.

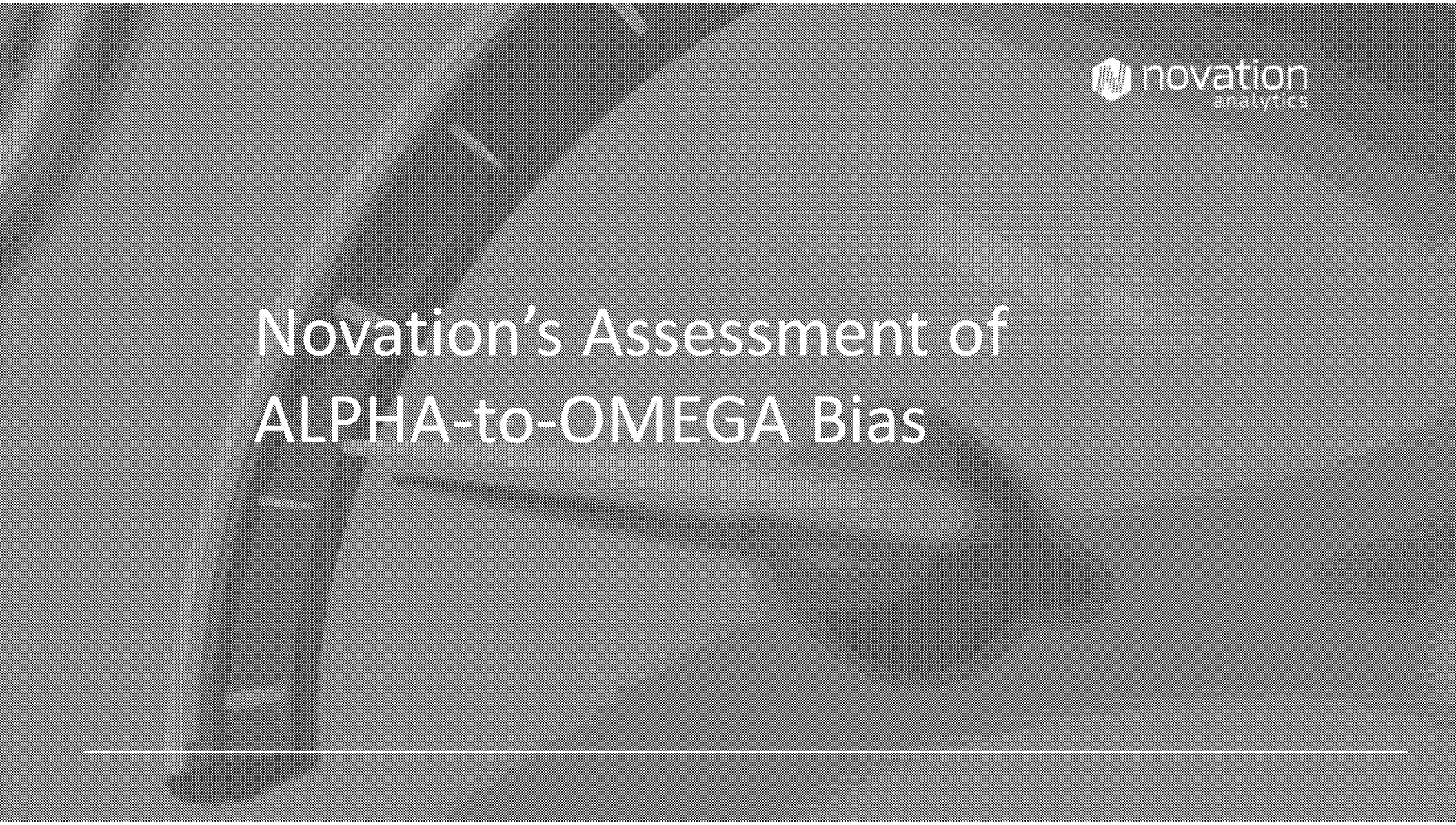


Key Takeaway: The EPA did not evaluate the LPM as implied in the Proposed Determination (TSD section 2.3.3.5.4, page 2-286)

EPA's ALPHA-to-LPM Bias Assessment

novation analytics

- Because of the discrepancies and limitations of EPA's ALPHA-to-LPM comparison, the EPA comparison depicted in its Figure 2.100 cannot serve as a reliable gauge of any bias in the ALPHA-to-LPM/OMEGA translation process.
- Consequently, EPA did not provide proof that the LPM/OMEGA process produces "*both small over-estimates and small under-estimates*", nor did it define "*small*" and show that these errors "*average out*".
- A deeper assessment of the LPM cannot be conducted without the specific details of the EPA process to translate the ALPHA model output to LPM model coefficients.



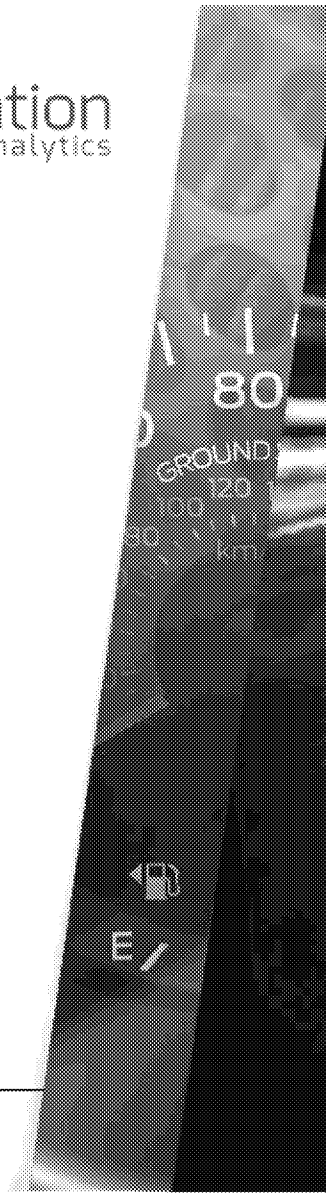
novation analytics

Novation's Assessment of ALPHA-to-OMEGA Bias

Alternate ALPHA-to-LPM Bias Assessment

novation analytics

- An alternate 0-D model, based directly on the published ALPHA simulation results, can be developed to assess ALPHA-to-LPM bias.
- *Novation's use of ALPHA modeling results for this purpose does not imply agreement with the ALPHA data.*

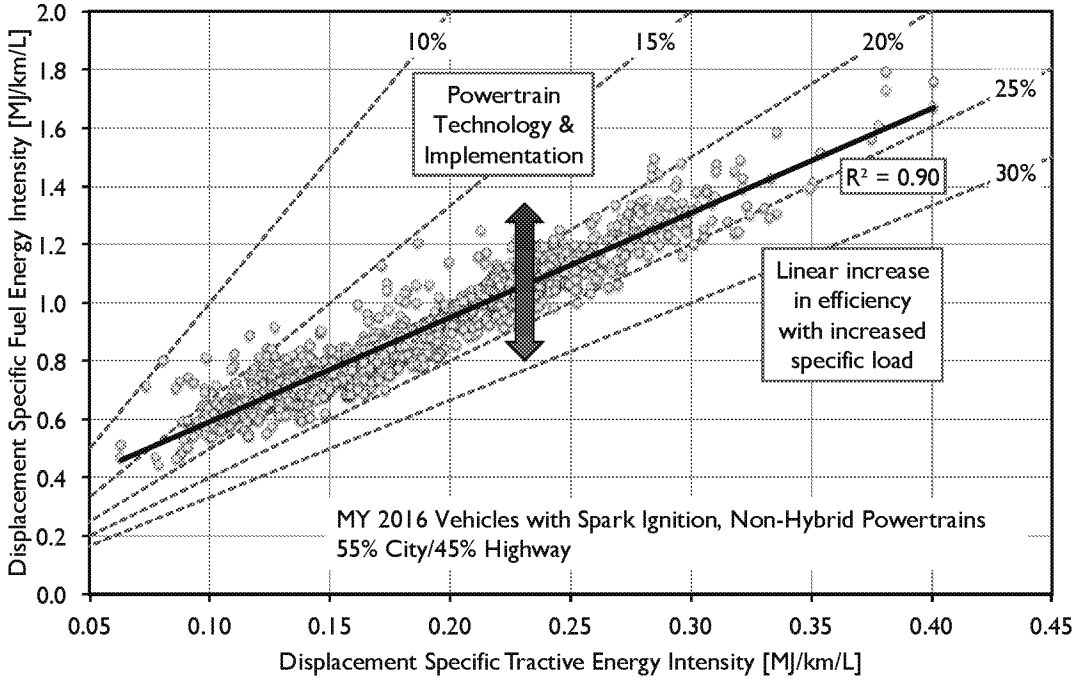


Displacement-Specific Energy Domain

novation analytics

When assessed in the displacement-specific energy domain, three key characteristics are expected of any simulation results:

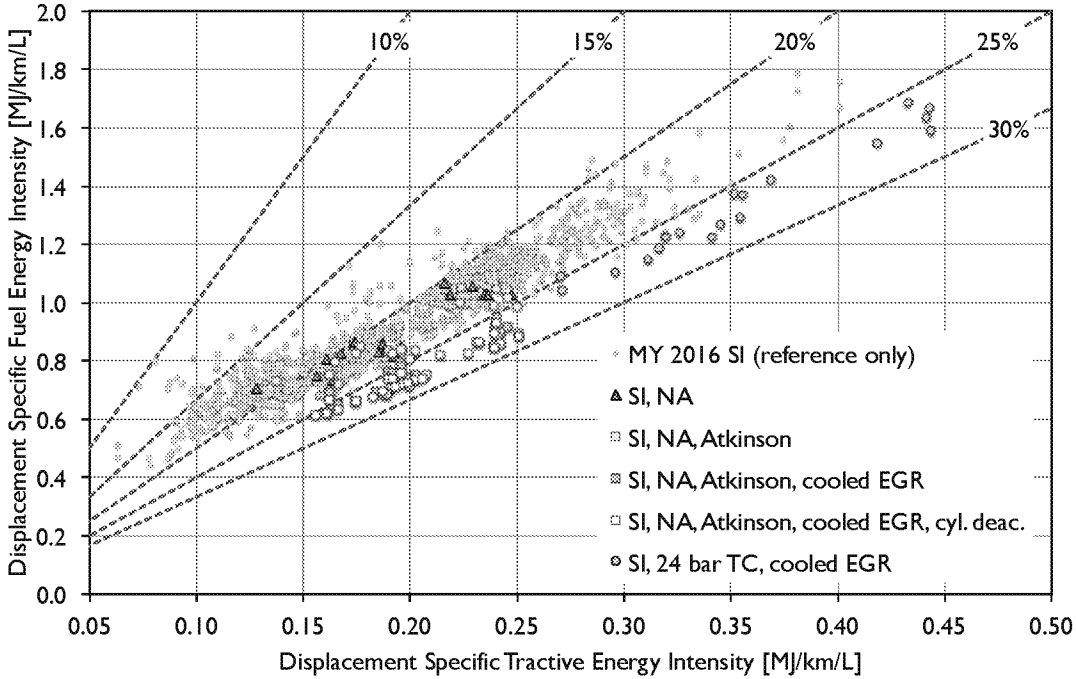
1. Linearity
2. Increasing efficiency with increasing displacement-specific tractive energy (within the range of FTP, HWFET)
3. Efficiency trends with technology



Displacement-Specific Energy: ALPHA

novation analytics

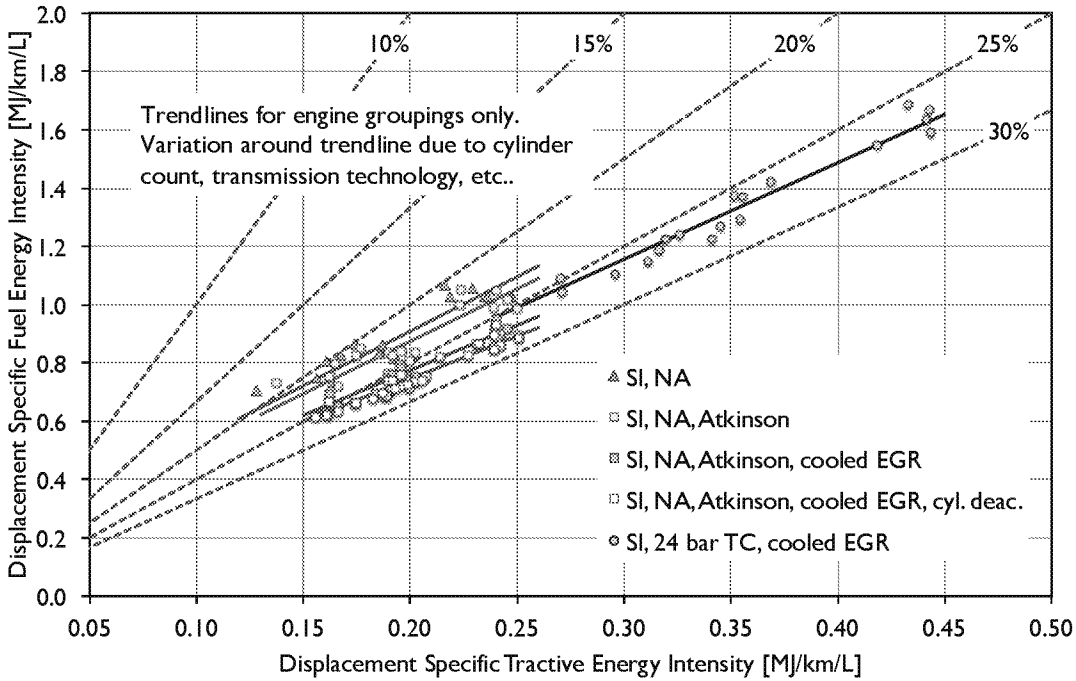
- The ALPHA PD results are shown in the displacement-specific energy domain.
- The SI/NA and SI/NA/Atkinson results lie within the MY 2016 reference vehicles. This is expected as the engine maps and simulation assumptions were largely based on actual tests.
- The Atkinson 2 and 24 bar BMEP TC results are higher than the MY 2016 reference vehicles. These simulations assumed advancements. The Atkinson 2 maps were created using GT Power.



Displacement-Specific Energy: ALPHA

novation analytics

- The ALPHA PD simulation results display the expected trends:
  - ✓ Linearity
  - ✓ Increasing efficiency with increasing displacement-specific tractive energy (FTP, HWFET)
- *The absolute levels of efficiency generated by ALPHA have not yet been assessed.*



Performance Neutral Displacement Estimates

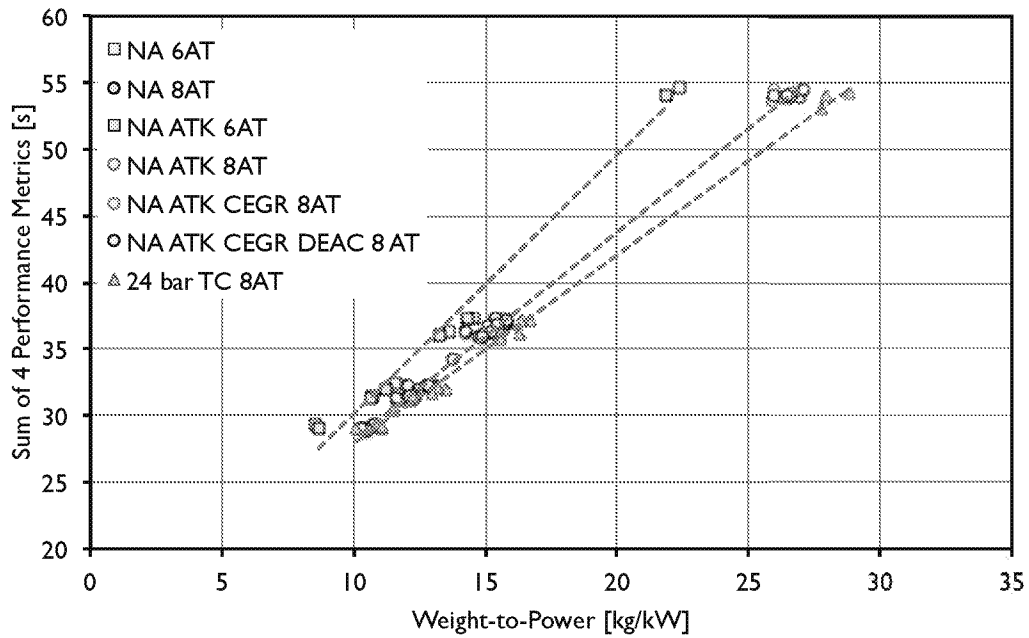
novation analytics

- To analyze LPM/OMEGA results in the displacement specific energy domain, the resulting engine displacement corresponding to each technology package is required.
- While OMEGA tracks the technologies applied and LPM-estimated effectiveness for each end state (technology package) in the optimized MY 2025 fleet, it does not provide the associated end-state engine displacement.
- By using EPA's Performance Neutrality assumption along with ALPHA modeled engine performance characteristics, and solving for the physics of acceleration performance, Novation can determine the corresponding displacement required by adding technology and altering vehicle weight.
- *Novation's use of ALPHA modeling results for this purpose does not imply agreement with the ALPHA data.*

Performance Neutral Weight-to-Power

novation analytics

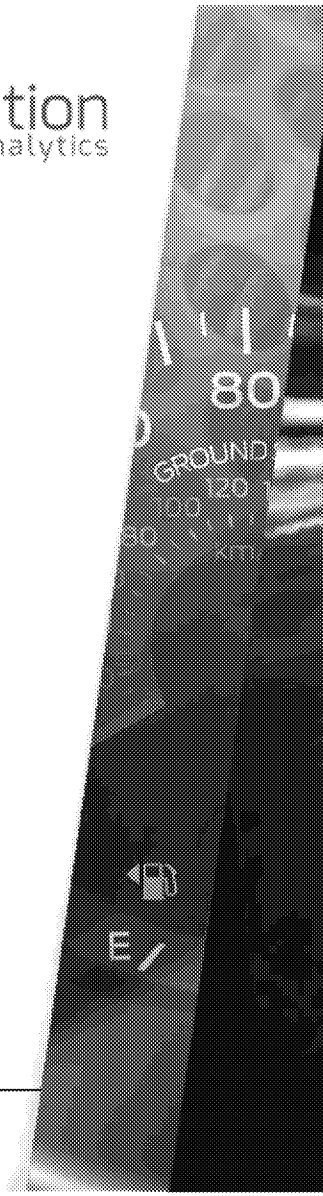
- Weight-to-power ratio is the primary predictor of acceleration performance. Secondary effects include transmission, gearing, torque, etc.
- The available ALPHA performance data reveals that, with the set of technology groupings established by the EPA, there are 3 secondary effects. The distinct groupings are:
  - SI-NA with TRX1 (6-speed ATX)
  - SI-NA with TRX2 (> 6 speed ATX)
  - 24-bar BMEP TC with TRX2
- A linear model of the Sum of 4 Performance Metrics, used by EPA, as a function of Weight-to-Power, TRX1, TRX2, and 24 bar TC was generated. R^2 of the resulting model is 97%.



Performance Neutral Weight-to-Power

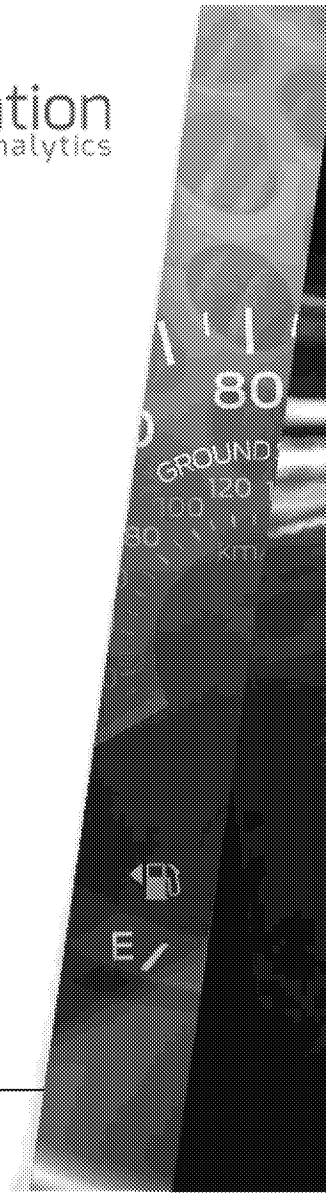
novation analytics

- From the performance model, weight-to-power technology multipliers were established to determine the final state weight-to-power ratio:
  - No change in engine or transmission technology, the weight-to-power technology multiplier is 1.0
  - NA TRX1 to NA TRX2 weight-to-power technology multiplier is 1.120
  - NA TRX1 to TC TRX2 weight-to-power technology multiplier is 1.173
  - NA TRX2 to TC TRX2 weight-to-power technology multiplier is 1.047
- These multipliers cover the technology changes for the 18% of the MY 2025 OMEGA population that have corresponding published ALPHA simulations.
- *Novation's use of ALPHA modeling results for this purpose does not imply agreement with the ALPHA data.*



Performance Neutral Displacement Estimates

novation analytics



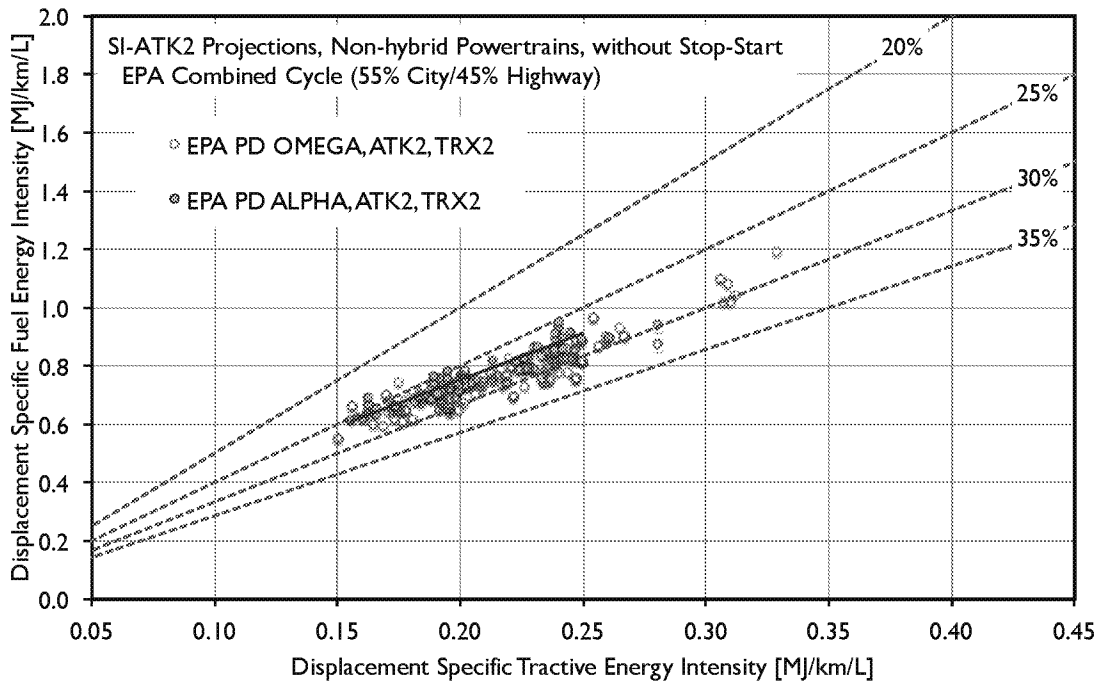
Computation Process:

1. Compute the weight-to-power ratio of the initial state, baseline (TP0, MY 2015) vehicles in the OMEGA file to establish the "performance neutral" condition.
2. Multiply the initial state weight-to-power ratio by the technology multiplier to determine the final state weight-to-power ratio required to maintain performance neutrality.
3. Compute the final state test weight from the OMEGA file data.
4. Divide the final state test weight by the final state weight-to-power ratio to determine the final state power requirement to achieve performance neutrality.
5. Dividing the final state power required by the EPA power density values for the published ALPHA data yields a performance neutral final state engine displacement.

OMEGA Comparison to ALPHA

novation analytics

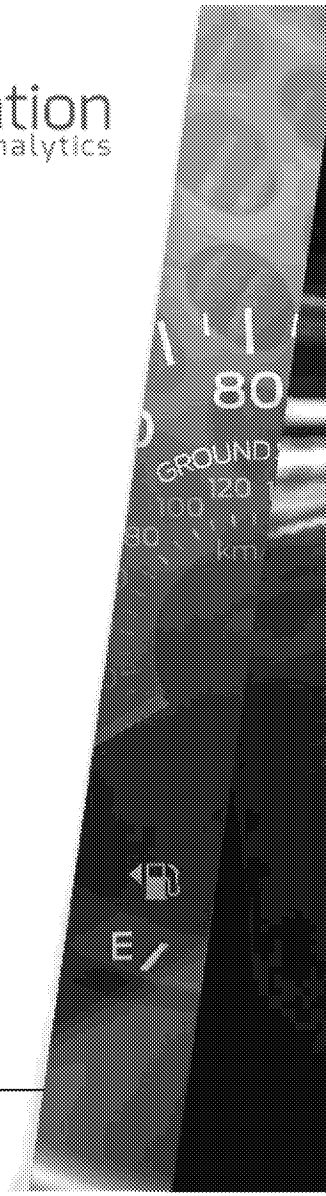
- Use of the OMEGA displacement estimates allows comparing the OMEGA data to ALPHA simulation results in the displacement specific energy domain.
- For example, the projections of Atkinson 2 technology are shown at the right. The OMEGA data exhibits a wider range of efficiencies than its underlying ALPHA data.
- The tractive energy range of the OMEGA data extends beyond the range of the ALPHA simulations, indicating extrapolation of the data beyond the range of the simulations, a potential source of error with 0-D models (LPM).



Alternate 0-D Model: Form

novation analytics

- As noted earlier, displacement-specific fuel energy is linearly correlated to displacement-specific tractive energy (surrogate for BMEP).
- This trend, often described as the Willans line, is well understood and relates engine output to energy input.
- To create the alternate 0-D model, Novation Analytics regressed the published ALPHA PD simulation results in the engine displacement-specific energy domain (both energy input and energy output).
- The final model form includes both the engine elements (e.g., NA, TC, Atkinson, cooled EGR, cylinder deactivation) and the transmission types. The published ALPHA results for driveline (e.g., FWD, RWD) did not yield a statistically significant difference.



Alternate 0-D Model: Form

novation analytics

Using the principles described, an engine displacement-specific zero-dimensional (0-D) model can be constructed with the form:

$$FC_{ds} = \beta_0 + \beta_1 \bullet TE_{ds}$$

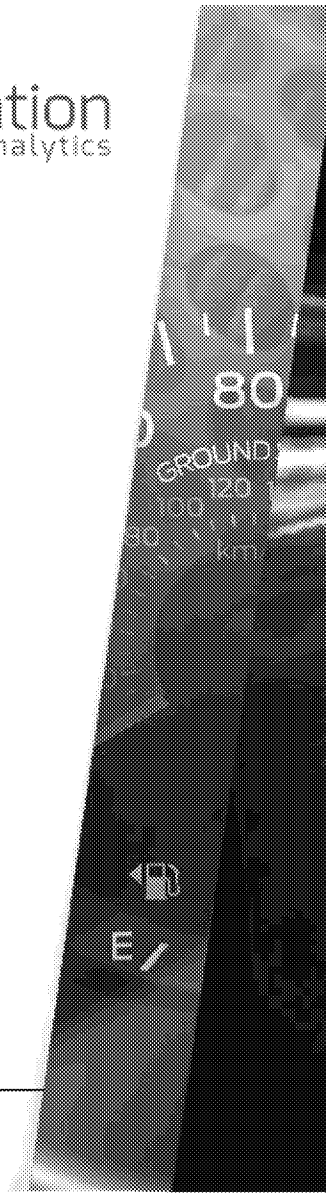
where:

FC_{ds} = displacement specific fuel consumption [MJ/km/L]

TE_{ds} = displacement specific tractive energy [MJ/km/L]

β_0, β_1 = model coefficients determined by linear regression

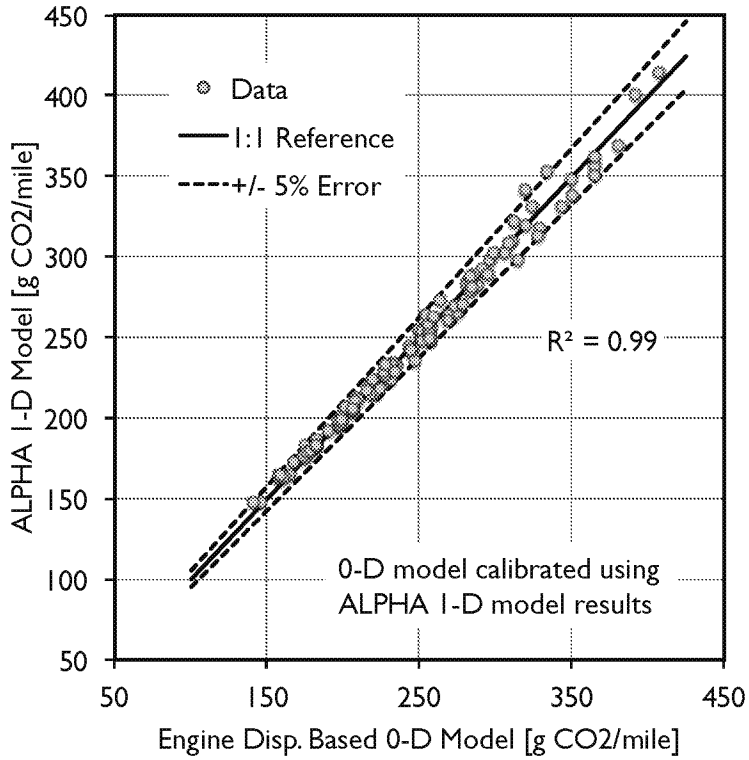
The model coefficients are evaluated for each powertrain bundle (i.e., each combination of engine, transmission, parasitic losses).



Alternate 0-D Model: Results

novation analytics

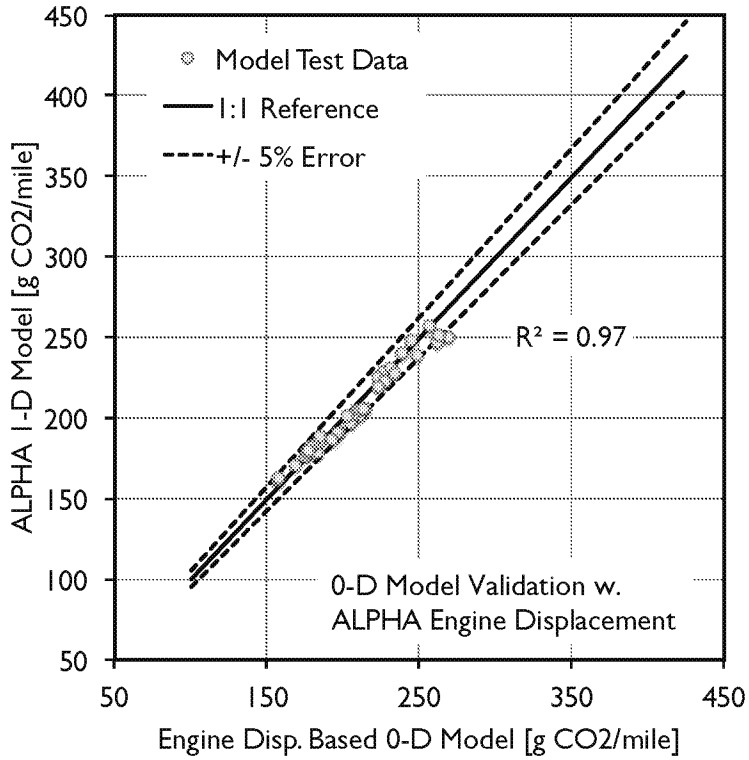
- The final form of the model yielded an R^2 of 0.99, meaning that it captured 99% of the variation among the 102 ALPHA simulation results provided with the PD.
- In the tailpipe CO_2 domain, the standard deviation was 6 g/mile (2.5% of the average CO_2).
- All but 3 of the alternate 0-D model results were within 5% of of the ALPHA results.
- The alternate 0-D model is un-biased as indicated by equal distribution of uncertainty around the 1:1 reference line.



Alternate 0-D Model: Validation

novation analytics

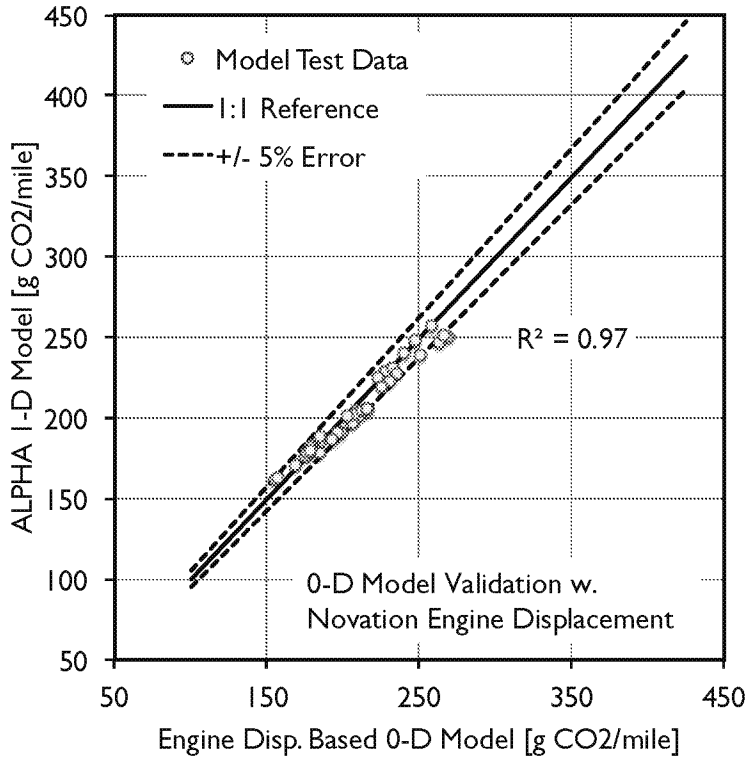
- Validation of Novation's alternate 0-D model was performed making use of EPA's provided ALPHA simulation results for the vehicles modeled in its Figure 2.100 analysis. These data were not used to develop the alternate 0-D model coefficients.
- Assuming the same engine displacement and tractive energy as the ALPHA simulations (i.e., same mass, aero and rolling resistance in the future tech state) the CO_2 estimates using the alternate 0-D model correlate well with ALPHA CO_2 projections.
- The Novation 0-D model had an average error of 1.4% versus the ALPHA simulation CO_2 values.



Alternate 0-D Model: Validation

novation analytics

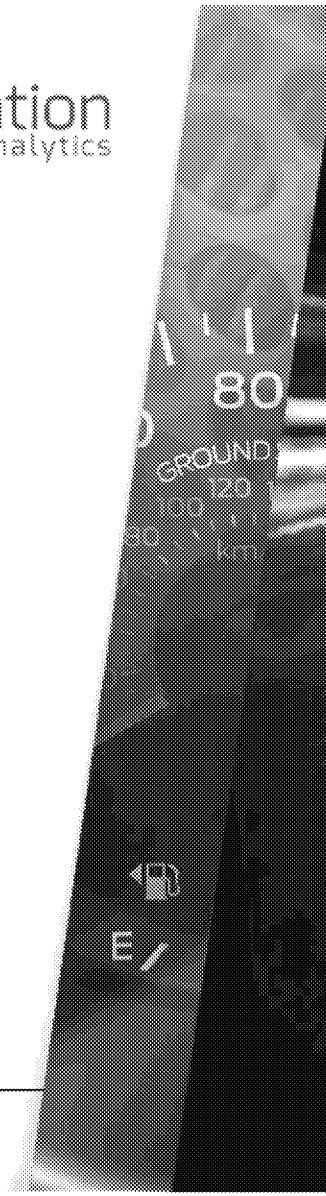
- In the 2nd step of validation, using Novation's performance neutral estimates of final state engine displacement, along with the ALPHA tractive energy (mass, aero, rolling resistance) values, the alternate 0-D CO_2 estimates correlate nearly as well with ALPHA CO_2 projections.
- This step validates the performance neutral engine displacement model in combination with the alternate 0-D displacement specific fuel consumption/CO_2 model.
- Put another way, the alternate 0-D model is relatively insensitive to error in the estimate of performance neutral engine displacement.
- In this case, the Novation 0-D model had an average error of 1.7% versus the ALPHA simulation CO_2 values.



Alternate 0-D Model: Bias Assessment

novation analytics

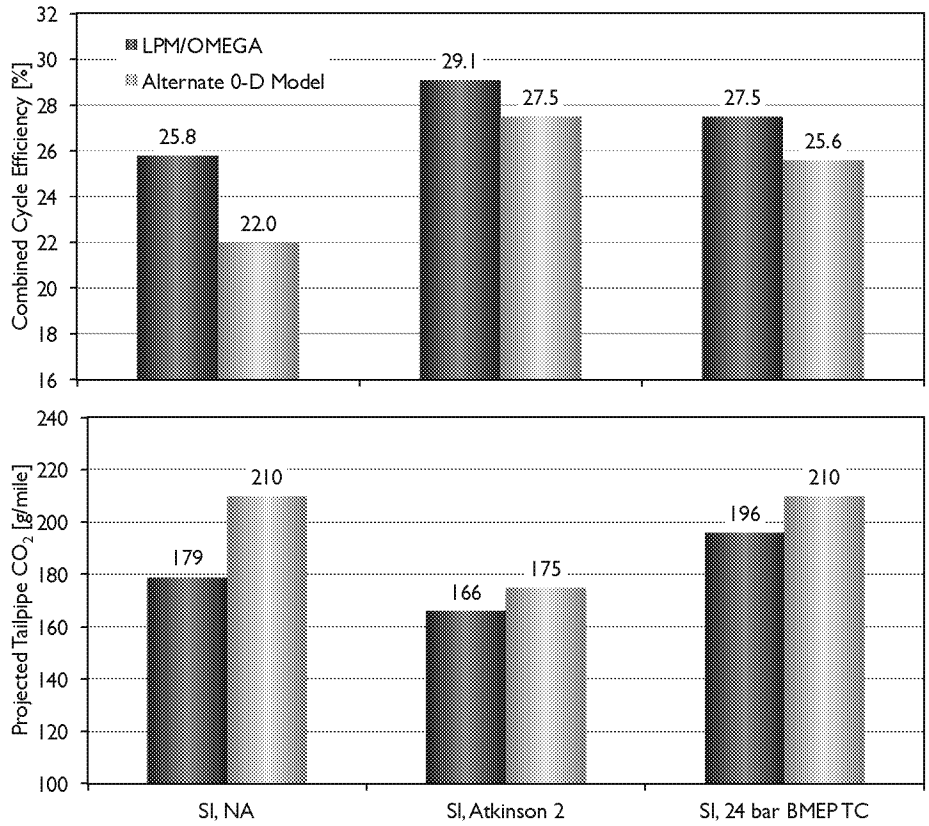
- Novation's alternate 0-D model, combined with the performance neutral displacement estimate methodology, can be used to generate independent estimates of vehicle-level CO_2 emissions.
- These alternate 0-D model vehicle-level CO_2 estimates are based directly on the published ALPHA simulations, bypassing the LPM process.
- These re-projected vehicle-level estimates can be compared directly to the vehicle-level estimates from the LPM/OMEGA process (MY 2025 OMEGA pathway results). The distribution of differences between these two sets of vehicle-level output would indicate the presence and direction of any bias in the ALPHA-to-LPM/OMEGA translation process.



Re-projected Vehicle Results

novation analytics

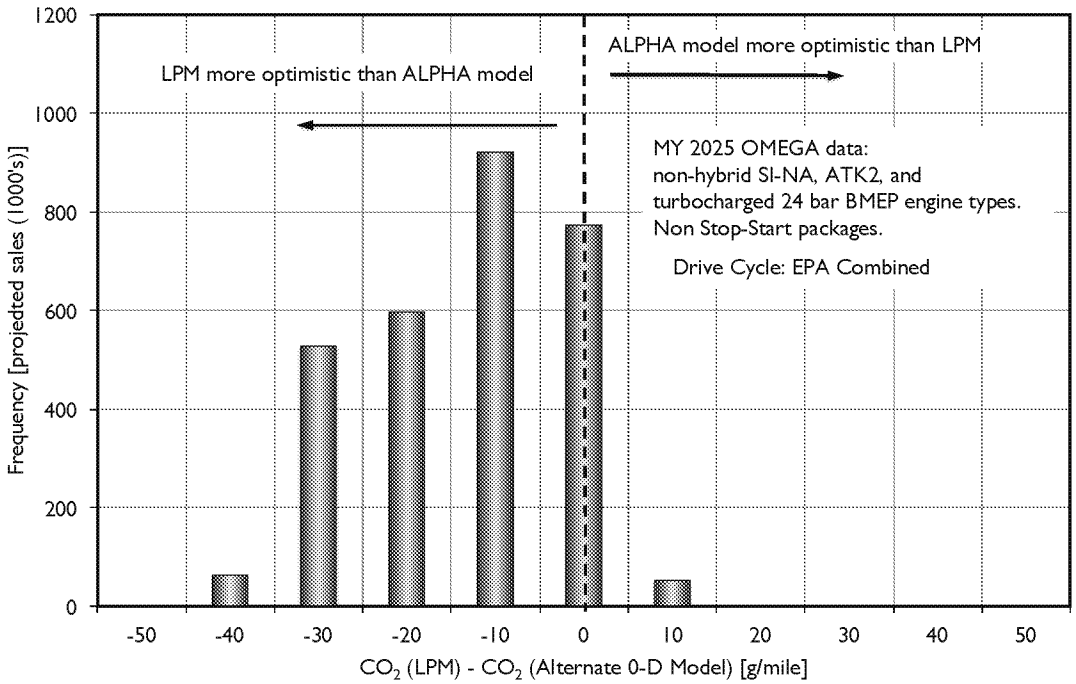
- For the segment of the MY 2025 fleet that were re-projected based on the alternate 0-D model, the resulting vehicle sub-population yields efficiency levels that are 5.5% to 14.7% lower than the LPM/OMEGA assessment.
- Corresponding tailpipe CO_2 projections are 5.4% to 17.3% higher.



Re-projected Vehicle Results

novation analytics

- The difference between the original (LPM/OMEGA) and the ALPHA based alternate 0-D model results indicates a negative (optimistic) bias of the LPM/OMEGA projections versus the ALPHA based projections.
- The alternate 0-D model yields a sales-weighted CO_2 difference of 13 g/mile (~8%) higher when compared to the LPM/OMEGA output for the same sub-population of vehicles.



novation analytics

Conclusions & Recommendations

Conclusions

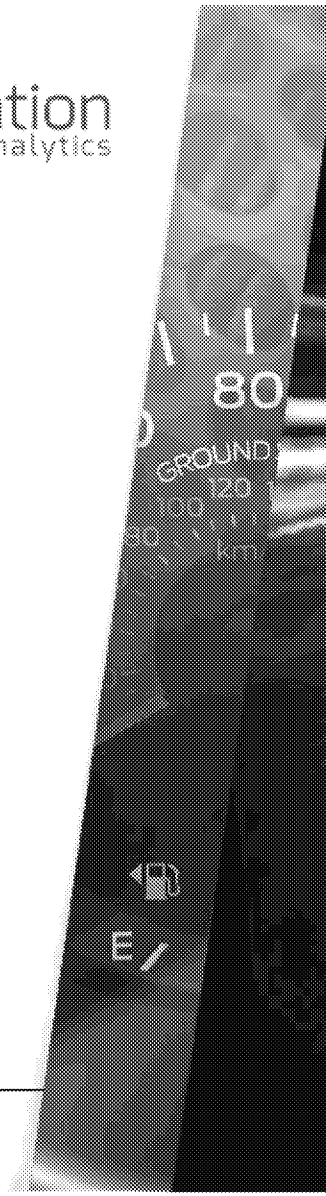
novation analytics

- EPA's use of power-to-weight ratio is not a robust surrogate for brake mean effective pressure. Additionally, its sub-classification (power-to-weight ratio and road load bins) provides little benefit.
- EPA's statement suggesting the LPM/OMEGA is an averaging process is unfounded based on a direct correlation of the ALPHA simulation results for multiple technology bundles.

Conclusions

novation analytics

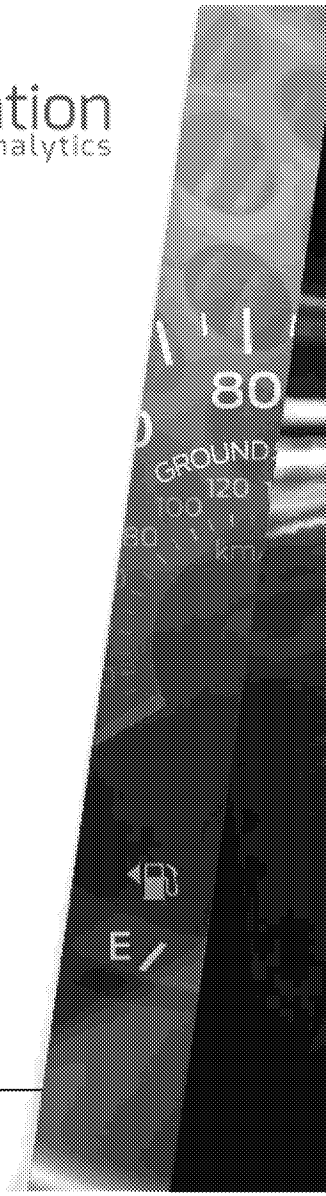
- Novation's alternate 0-D model, based directly on the available ALPHA simulation data, confirms a high efficiency (low CO_2) bias in the LPM/OMEGA estimates, minimally for the segment of the vehicle population represented by ALPHA simulations (~ 18% of the fleet).
- Based on the alternate 0-D modeling results, the LPM/OMEGA CO_2 levels are estimated to be 5% to 17% lower than underlying ALPHA simulation results, depending upon the technology bundle.
- The resulting LPM/OMEGA bias, if consistent across the entire fleet, represents approximately one-third of the EPA projected CO_2 reductions over the MY 2022-2025 timeframe.



Recommendations

novation analytics

- Power-to-weight ratio and road load binning should not be used in the 1-D to 0-D modeling step (e.g., Autonomie to Volpe, or ALPHA to LPM/OMEGA).
- For the 1-D to 0-D modeling step, if this approach is retained, consider the use of alternate 0-D models based on displacement-specific energy.
- Since practical solutions do exist, consider eliminating the 0-D model step and generating CO_2 and fuel economy values for all vehicles and their technology scenarios using 1-D (full-scale) simulations.

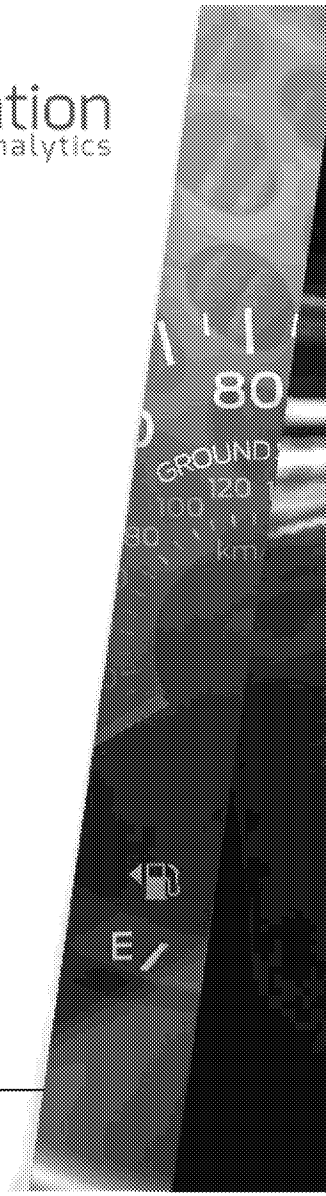


Contact

novation analytics

Mike Reale, Director, Global Regulatory Analysis
mreale@novationanalytics.com
(313) 600-2181

Greg Pannone, President
gpannone@novationanalytics.com
(313) 910-3280



Trade Association Concerns with EPA Modeling for the MTE

September 21, 2017

GlobalAutomakers

AUTO ALLIANCE
DRIVING INNOVATION

Summary of Concerns with EPA Modeling

- In general, EPA models appear to overestimate effectiveness and underestimate costs
- Our analysis between EPA's two models ALPHA (used to calibrate LPM) and LPM (used to set the standards) shows significant differences in output between the two
  - **Converted into years of compliance, differences between EPA's own models could account for 1 to 4 years of compliance – slide 40 of presentation**
  - These errors do not cancel out. Our analysis shows about 2 years of compliance shortfall due to possible LPM to ALPHA differences alone – slide 41
    - This does not include concerns with other input assumptions and ALPHA\OMEGA modeling issues
- High level quality checks are needed to catch and systematically address/ prevent issues
  - The lack of transparency with the OMEGA assumptions mean we cannot provide a thorough quality check of them in our analysis
  - The OMEGA model appears to largely ignore real world constraints such as product launch cadence, implementation, intellectual property, manufacturer technology plans and incorrectly applies mass reduction, aero, and tire improvements.
  - The modeling assumes a proliferation of vehicle packages (3,130 in 2015 to 7,246 in 2025)
- Separate from this analysis, concerns about MY 2016 and MY 2017 compliance remain

GlobalAutomakers

AUTO ALLIANCE
DRIVING INNOVATION

Alliance/Global Automakers meeting to present Novation Analytics studies - Mozilla Firefox

Reply Reply All Forward

Alliance/Global Automakers meeting to present Novation Analytics studies

Moran, Robin [moran.robin@epa.gov]

Required: [illegible]

Optional: [illegible]

Attachments: [illegible]

Sent: Thursday, September 28, 2017 12:07 PM

When: Thursday, September 28, 2017 1:00 PM-2:00 PM.

Where: Call In: 866-299-3188; Code 734-214-4781; AA Room-Office-C126-ConRoom/AA OTAQ OFFICE

- Accepted on 9/29/2017 9:43 AM
- This appointment has already occurred.

Reminder: 15 minutes Show time as: Busy Private

Description:

The EPA presentation is attached.

Note that the agenda has changed slightly per the Alliance's request. The Alliance indicated that the Novation briefing will not discuss the "baseline study" during this meeting, and will focus on the ALPHA to LPM step of the modeling process.

Agenda

1. Novation Analytics Briefing
2. Summary Thoughts on MTE Modeling from Trade Associations
3. EPA Presentation: Powertrain efficiency in EPA's technical assessment to-date, and plans for ongoing updates
4. Discussion

Call-In: 866-299-3188; code 734-214-4781

WebEx connection : http://epawebconferencing.acms.com/mte-stakeholder/

Message

From: Eric Byer [ebyer@NACD.com]
Sent: 9/28/2017 11:48:30 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Pestering

Hey you been able to ask Nancy?

On Sep 25, 2017, at 3:37 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hey – sorry. I've been trying to make this work, but I will be in Germany on the 13th at the COP, so unable to make it. Do you want me to ask someone else?
> Best,
> Mandy
>
> ---
>
> **From:** Eric Byer [mailto:ebyer@NACD.com]
> **Sent:** Monday, September 25, 2017 2:27 PM
> **To:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Pestering
>
> Hey, sorry for nagging. Annual meeting in San Antonio on November 13. Can you swing? Thanks, EB

Message

From: Niina Heikkinen [nheikkinen@eenews.net]
Sent: 9/21/2017 8:53:13 PM
To: Bowman, Liz [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=c3d4d94d3e4b4b1f80904056703ebc80-Bowman, Eli]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Graham, Amy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=26722dfde5b34925b0ad9a8dd4aff308-Graham, Amy]; Abboud, Michael [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=b6f5af791a1842f1adcc088cbf9ed3ce-Abboud, Mic]; Wilcox, Jahan [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=88fd588e97d3405d869bcae98d391984-Wilcox, Jah]
Subject: RE: question

Got it, while I have you, any comment for the record on plans to release Pruitt's schedule bi-weekly? Sen. Carper seems to think this is real. Any details about what kind of info will be in the schedule will be helpful.

Best,

Niina

From: Bowman, Liz [mailto:Bowman.Liz@epa.gov]
Sent: Thursday, September 21, 2017 4:38 PM
To: Gunasekara, Mandy; Niina Heikkinen
Cc: Graham, Amy; Abboud, Michael; Wilcox, Jahan
Subject: RE: question

Hi Niina – Please reach out to the White House directly for information about meetings they hosted. Thank you -- Liz

---

From: Gunasekara, Mandy
Sent: Thursday, September 21, 2017 4:28 PM
To: Niina Heikkinen <nheikkinen@eenews.net>
Cc: Bowman, Liz <Bowman.Liz@epa.gov>; Graham, Amy <graham.amy@epa.gov>
Subject: RE: question

Hi Niina,
Thank you for the outreach. I'm cc'ing out press team who can help assist with a response.
Best,
Mandy

From: Niina Heikkinen [mailto:nheikkinen@eenews.net]
Sent: Thursday, September 21, 2017 4:23 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: question

Hi,

I was checking in to see if you were one of the people participating in the White House meeting yesterday reported by Politico. If so, could you give me a sense of what may have been discussed?

Thanks very much for your help.

Best,

Niina Heikkinen
E&E News reporter
202-737-3715 (w)
413-687-1789 (c)
@nhheikkinen
Skype: niina.h.heikkinen

E&E NEWS
122 C Street NW 7th Floor Washington, DC 20001
www.eenews.net | @EENewsUpdates
Energywire, Climatewire, Greenwire, E&E Daily, E&E News PM

Message

From: Tracy Fedkoe [TFedkoe@AWMA.ORG]
Sent: 9/18/2017 6:52:40 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Cindy Fontanesi [CFontanesi@AWMA.ORG]; jcmuffat [jcmuffat@yahoo.com]
CC: CC Conference 2017 [CCConference2017@AWMA.ORG]; Webb, C. Flint [C.FLINT.WEBB@leidos.com]
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA

Hi Mandy,

Glad to have you on board for the conference keynote. We will use your photo and title on the website. We are planning to send out a promotion very soon to announce your participation. Here's what I would like to use, but I need a little information on the topic(s) you will be addressing in your presentation.

> **Additional keynote speaker added!**
>
> Mandy Gunasekara, Senior Policy Advisor to the Administrator for the USEPA Office of Air and Radiation, will be opening the conference on Tuesday with an presentation on . . . .
>
> Additional keynote presentations include:
>
> - California's Perspective on the Need for Climate Change Action
> Michael McCormick, Senior Planner, California Governor's Office of Planning and Research
>
> - Climate Change: The Imperative to Increase Global Resilience
> Vice Admiral Dennis V. McGinn, United States Navy (retired), Member of the Advisory Board, The Center for Climate Security, Former Assistant Secretary of the Navy for Energy, Installations, and Environment, and Former Deputy Chief of Naval Operations for Warfare Requirements and Programs

We hope to send this out tomorrow if possible. I realize this is short notice, so if you're not quite ready to list a topic, we can just use your title and add that to the Final Program later.

Thanks in advance for your response.

Regards,

Tracy Fedkoe
Director, Marketing and Project Management
Air & Waste Management Association
412-904-6028

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, September 18, 2017 2:43 PM
To: Cindy Fontanesi <CFontanesi@AWMA.ORG>; jcmuffat <jcmuffat@yahoo.com>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; CC Conference 2017 <CCConference2017@AWMA.ORG>
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10-11 Arlington VA

That title is correct. Also, attached is my photo. Let me know if you need a different size.

-----Original Message-----
From: Cindy Fontanesi [mailto:CFontanesi@AWMA.ORG]
Sent: Monday, September 18, 2017 2:37 PM
To: jcmuffat <jcmuffat@yahoo.com>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; CC Conference 2017 <CCConference2017@AWMA.ORG>
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10-11 Arlington VA
Importance: High

Hello Jeff & Mandy,

Can one of you please confirm Mandy's official title? This is what we found online:
Senior Policy Advisor to the Administrator for the Office of Air and Radiation

Also, if you have a photo of Mandy to send to us that would be great too. Please let me know if you have any questions.

Thank you again,

Cindy Fontanesi
Conference & Events Planner
Air & Waste Management Association
One Gateway Center, Third Floor
420 Fort Duquesne Blvd
Pittsburgh, PA 15222
(t) 412-904-6031
(f)412-232-3450
Please consider the environment before printing this e-mail

> On Sep 14, 2017, at 2:34 PM, Cindy Fontanesi <CFontanesi@AWMA.ORG> wrote:
>
> Hi Mandy,
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. For now, I need your preferred name and title, the title of your Keynote, and your mailing address so that we can get you officially registered for the conference. Also, please let me know if you have any special requirements for your Keynote. We will provide the standard set for audiovisuals which is an LCD projector, laptop computer, screen, laser pointer, and microphone.
>
> You are scheduled to present on Tuesday, October 10, 2017 from 8:30 am - 9:00 am. There will be a Presenters' Meeting at 7:30 am on the day of your involvement. The format of the program is discussed at this time. The Presenters' Meeting is also a good time to load your presentation in the session room and check your audiovisuals.
>
> If you'd like to take a look at the preliminary program for the conference, it can be found on our website at https://www.awma.org/climatechange. We will add your Keynote information to the conference website asap and to the final program, which will be released to the public on September 29th.
>
> The conference is being held at the DoubleTree by Hilton Washington DC - Crystal City - 300 Army Navy Drive - Arlington, VA 22202. Please let me know if you have any questions or needs along the way. I look forward to working with you and meeting you at the conference in a few weeks!
>

> Thank you,
>
> Cindy Fontanesi
> Conference & Events Planner
> Air & Waste Management Association
> One Gateway Center, Third Floor
> 420 Fort Duquesne Blvd
> Pittsburgh, PA 15222
> (t) 412-904-6031
> (f)412-232-3450
> Please consider the environment before printing this e-mail
>
>
>
> -----Original Message-----
> From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
> Sent: Thursday, September 14, 2017 9:26 AM
> To: jcmuffat <jcmuffat@yahoo.com>
> Cc: William L. Wehrum <wwehrum@hunton.com>; Cindy Fontanesi <CFontanesi@AWMA.ORG>
> Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Hi Jeff,
> Thank you for the information and I look forward to connecting with Cindy.
> Best,
> Mandy
>
> -----Original Message-----
> From: Jeffry Muffat [mailto:jcmuffat@yahoo.com]
> Sent: Thursday, September 14, 2017 8:08 AM
> To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> Cc: William L. Wehrum <wwehrum@hunton.com>; cfontanesi@awma.org
> Subject: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Mandy:
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. The Conference is scheduled for Oct 10-11, 2017 in Arlington, VA and promises to be a great opportunity to exchange meaningful information on the current thinking relative to climate change and how we can mitigate any adverse effects and adapt to the potential consequences. The Association values EPA's thinking and is excited to provide the forum for discussion to our membership and other parties involved in the discussion.
>
> Bill Wehrum said that you planned to check with Administrator Pruitt one last time to see if he was available to Keynote and it would be great if he wanted to speak. However, our intent at this time is to list you in the Program at the Keynoter and then to send out a special mailing/notice announcing Administrator Pruitt as the Keynoter should he decide to speak.
>
> Cindy Fontanesi from A&WMA Headquarters in Pittsburgh will be in touch with you today to work out the details.
>
> Again, thank you so much for agreeing to speak at our upcoming Conference.
>
> Jeff Muffat

> Retired Manager of 3M Environmental Reg Affairs Treasurer of Air & Waste Management Association .
>
>
> ----------
>
> This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
> https://us1.proofpointessentials.com/index01.php?mod_id=11&mod_option=logitem&mail_id=1505395557-Zfwis8S5ZWjM&r_address=cfontanesi%40awma.org&report=

.

This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
https://us1.proofpointessentials.com/index01.php?mod_id &mod_option=gitem&mail_id 05418758-QepsfQTnqxHw&r_address►ontanesi%40awma.org&report=

Message

From: Courtney Cook [CCook@alec.org]
Sent: 9/16/2017 2:42:47 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: ALEC - Be the first to hear!

2017 States & Nation Policy Summit

Join us in Nashville
December 6 - 8, 2017

Policy Highlights

Interested in having a more prominent role and connecting

with 800+ legislators and business leaders from across the country? Consider making your mark in our Exhibitor Hall.
Secure your spot today!

Shelby Emmett, Director of the ALEC Center to Protect Free Speech will be discussing issues around free speech at our upcoming States & Nation Policy Summit. Register today to be a part of the the discussion on the FORUM Act and what is means for University's in your state.

Invited Speakers Include...

A Tennessee Welcome from Senator Alexander, Senator Corker, Representative Black and Representative Blackburn

Secretary Tom Price

Administrator Scott Pruitt

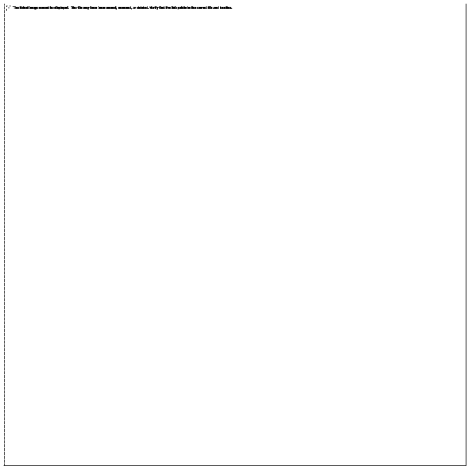
A panel presentation from Mr. Steve Forbes, Mr. Steve Moore, Dr. Art Laffer and Mr. Larry Kudlow

Agenda at a Glance

Visit the online agenda for more information!

Tuesday	Wednesday	Thursday	Friday
· Registration	· Registration	· Registration · **Breakfast**	· Registration · **Breakfast**
· Exhibitor Set-up	· Exhibit Hall	· Exhibit Hall	· Exhibit Hall
	· Subcommittee Meetings	· Training	· Training
	· Legislative Staff Fellowship	· Legislative Staff Fellowship	· Legislative Staff Fellowship
	· Training · **Opening Lunch**	· Workshops · **Lunch**	· Workshops · **Lunch**
	· Workshops	· Task Force Meetings	· Task Force Meetings
	· Chair's Reception	· Task Force Receptions	· Task Force Receptions

- Welcome Reception
- Jefferson Awards Reception and Dinner **(Invitation Only)**
- State Night **(Contact your State Chair for more Information)**



This message was sent to gunasekara.mandy@epa.gov from CCook@alec.org

Courtney Cook
ALEC
2900 Crystal Drive, 6th Floor
Arlington, VA 22202

Unsubscribe

Message

From: Clint Woods [cwoods@csg.org]
Sent: 9/22/2017 1:58:18 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: inside epa
Attachments: image001.jpg

Begin forwarded message:

DAILY NEWS

EPA Plans 'Key Revisions' To CSAPR Methods As States Criticize Program

September 21, 2017

EPA is making "key revisions" to its methods for projecting interstate air pollution from power plants and the oil and gas sector under its Cross-State Air Pollution Rule (CSAPR) emissions trading framework, but several Southern states are criticizing the overall framework as inappropriate for mitigating cross-state air pollution.

The changes to the methodologies, announced at the Sept. 21 fall meeting of the Association of Air Pollution Control Agencies (AAPCA), follow **competing criticisms** states raised earlier this year over a data notice the Obama EPA issued for CSAPR. East Coast states argued the notice underestimated ozone from upwind emissions sources, while upwind states said it showed cross-state linkages in pollution where there are none.

Tyler Fox of EPA's Office of Air Quality Planning & Standards (OAQPS) said in **a presentation** to AAPCA that the air quality modeling conducted by the Obama EPA to support state efforts to curb interstate pollution faces significant change, primarily affecting how the agency projects emissions from utilities and oil and gas operations -- though his presentation does not elaborate on how the methods for projecting emissions will change.

Still, he said that the changes will help states as they write their state implementation plans (SIPs) outlining the pollution control measures they will impose to attain EPA's ozone national ambient air quality standards (NAAQS), including the 2008 limit of 75 parts per billion (ppb) and the 2015 limit of 70 ppb.

Among the plans that states have to craft are "good neighbor" SIPs required by the Clean Air Act to show that their emissions will not hinder another state from being able to attain the NAAQS.

CSAPR, which caps nitrogen oxides (NOx) and sulfur dioxide from power plants, is designed to help states meet the ozone standards through a cap-and-trade emissions program. In January, EPA issued a notice of data availability (NODA) outlining its draft modeling of upwind states' contributions to problems attaining and maintaining the NAAQS. The modeling is intended to serve as a basis for states to craft good neighbor SIPs.

The trading rule was designed to help states meet the 1997 ozone NAAQS expressed as 84 ppb and the 2008 limit. Although there is no such trading rule in place to help states in meeting the tougher 2015 NAAQS of 70 ppb, the January NODA uses the CSAPR methodology already tested extensively in the courts.

But Fox's presentation to AAPCA -- representing several state and local air quality divisions -- says that in response to public comments on the January NODA the agency is changing some methodologies.

Modeling Update

"We are updating this modeling based on NODA comments and other factors to identify nonattainment and maintenance receptors and interstate 'linkages' for 2023," Fox said, with changes for electric generating units (EGUs) and oil and gas production the most prominent revisions.

Upwind states, many of which are located in the South and Midwest and represented by AAPCA, were critical of the NODA, claiming it uses faulty methods and overstates their contribution to NAAQS attainment problems downwind. The NODA uses 2023 as its "future analytic year" to determine states' contribution to interstate emissions problems.

Other states, such as the 12-state Ozone Transport Commission of Eastern downwind states, were also critical of the NODA modeling, but for different reasons, faulting its accuracy for possibly understating emissions.

In response, "Key revisions have been made to the methodologies for projecting emissions for EGUs and the oil and gas sector in addition to updates on plant closures," Fox said.

"We believe this modeling can serve multiple purposes in helping states develop SIPs" to meet the 2008 ozone standards, and it "will also be informative for future 2015 ozone NAAQS transport SIPs," he added.

Ordinarily, transport SIPs would be due from states in October 2018 to meet the 2015 ozone NAAQS, in line with a statutory deadline of Oct. 1 this year for designation of areas as either attainment or nonattainment for the standard. However, EPA has indicated it will likely miss this deadline for at least some areas.

Anna Marie Wood, director of the Air Quality Policy Division of OAQPS, said in **her Sept. 21 presentation to AAPCA** that EPA Administrator Scott Pruitt "may determine that an extension of time to complete designations," as permitted by the Clean Air Act, "is necessary" for some areas.

The air law allows EPA to extend the deadline for designation by one year, from two years to three years after issuance of a new NAAQS. But the Trump EPA faced criticism and litigation from environmentalists and others when it attempted to delay all 2015 ozone designations by a year citing insufficient data to designate, and ultimately withdrew its decision. This leaves open the possibility of case-by-case delays for specific areas.

States' Criticisms

Meanwhile, Georgia, North Carolina and Tennessee in **a Sept. 21 joint presentation to AAPCA** say EPA must revise its broader CSAPR approach that underlies the trading program and NODA.

The states take issue with EPA's method for identifying downwind air monitors, or "receptors," that should be included in the interstate pollutant transport analysis. Only receptors located in areas actually designated nonattainment for the 2015 ozone NAAQS should be included, and those in areas never so designated should be exempt, they argue. This differs from EPA's approach, which relies on projected nonattainment, not actual designation.

Further, monitors with "design values" -- a measure of ozone levels -- currently below the 2015 NAAQS "should be removed from the analysis," regardless of whether those monitors fall in areas actually designated nonattainment, according to the presentation.

The states' comments also reflect unease among some states and industry over how EPA determines "maintenance" areas to include in the analysis. Maintenance areas are those that were once in nonattainment but have now come into attainment, although under the NODA methodology the precise formula used by EPA is more complex, and is contested.

"EPA's approach results in over-control of NOx emissions in the upwind states," they say.

The Supreme Court has upheld most aspects of the CSAPR methodology, but did find that EPA must not "over-control" states by requiring them to reduce emissions by more than is required to have all downwind areas to which they contribute significantly attain and maintain the NAAQS.

The three states say that bias in the model used by EPA could undermine the results. They further say EPA's threshold for determining whether a contribution to downwind attainment problems is "significant," at 1 percent of the NAAQS -- in this case, 0.07 ppb -- "is arbitrary and has never been supported by any scientific analysis." They suggest instead a significance threshold of 1 ppb, in effect, excluding more areas from good neighbor obligations. -- *Stuart Parker*(**sparker@iwpnews.com**)

AAPCA ASSOCIATION OF AIR POLLUTION CONTROL AGENCIES

2017 FALL BUSINESS MEETING

September 20–22 | Doubletree by Hilton | Raleigh, North Carolina

Message

From: Jason Sloan [jsloan@csg.org]
Sent: 9/18/2017 4:05:47 PM
To: Jason Sloan [jsloan@csg.org]
Subject: Reminder: Presentations for AAPCA's 2017 Fall Business Meeting

Speakers,

We look forward to seeing you at AAPCA's 2017 Fall Business Meeting in Raleigh, North Carolina later this week. If available, please provide your presentation materials to jsloan@csg.org by 6:00 PM Eastern today, September 18. If you are unable to send, please bring the presentation on a USB drive so we are able to transfer it to the computer for viewing.

Thanks!

Jason E. Sloan
Policy and Membership Associate
Association of Air Pollution Control Agencies
1776 Avenue of the States
Lexington, KY 40511
859.244.8043 – office
jsloan@csg.org
http://www.cleanairact.org

Message

From: Lisa Jacobson [ljacobson@bcse.org]
Sent: 9/25/2017 5:00:27 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: BCSE Meeting

Thank you for letting me know Mandy. Is there a designee that can attend in your place? Or would it be helpful to select a different date and time to meet in the next two or three weeks? This is a very high priority for our members and welcome your advice on how to move forward. Thank you again, Lisa

Personal Phone / Ex. 6

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, September 25, 2017 12:09 PM
To: Lisa Jacobson <ljacobson@bcse.org>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: BCSE Meeting

Hi Lisa,
I apologize for the late notice, but I will not be available for the Oct. 5 meeting. Please keep me in mind for future opportunities and I look forward to working together on the range of issues that are important to both the agency and BCSE.
Best,
Mandy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: The White House [noreply@whitehouse.gov]
Sent: 9/27/2017 7:56:22 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RSVP Confirmation

THE WHITE HOUSE
WASHINGTON

Dear Amanda,

Thank you for submitting your RSVP. We have received your information. Please reach out to your point of contact with any questions.

Sincerely,
The White House

The White House • 1600 Pennsylvania Avenue, N.W. • Washington, D.C. 20500 • 202-456-1111

Message

From: Jeffry Muffat [jcmuffat@yahoo.com]
Sent: 9/18/2017 6:44:17 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Cindy Fontanesi [CFontanesi@AWMA.ORG]
CC: Tracy Fedkoe [TFedkoe@AWMA.ORG]; CC Conference 2017 [CCConference2017@AWMA.ORG]
Subject: Re: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA

Thanks for the quick confirmation Mandy.

Jeff

Sent from Yahoo Mail for iPad

On Monday, September 18, 2017, 1:42 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

That title is correct. Also, attached is my photo. Let me know if you need a different size.

-----Original Message-----
From: Cindy Fontanesi [mailto:CFontanesi@AWMA.ORG]
Sent: Monday, September 18, 2017 2:37 PM
To: jcmuffat <jcmuffat@yahoo.com>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Tracy Fedkoe <TFedkoe@AWMA.ORG>; CC Conference 2017 <CCConference2017@AWMA.ORG>
Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" October 10- 11 Arlington VA
Importance: High

Hello Jeff & Mandy,

Can one of you please confirm Mandy's official title? This is what we found online:
Senior Policy Advisor to the Administrator for the Office of Air and Radiation

Also, if you have a photo of Mandy to send to us that would be great too. Please let me know if you have any questions.

Thank you again,

Cindy Fontanesi
Conference & Events Planner
Air & Waste Management Association
One Gateway Center, Third Floor
420 Fort Duquesne Blvd
Pittsburgh, PA 15222
(t) 412-904-6031
(f)412-232-3450
Please consider the environment before printing this e-mail

> On Sep 14, 2017, at 2:34 PM, Cindy Fontanesi <CFontanesi@AWMA.ORG> wrote:
>
> Hi Mandy,
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. For now, I need your preferred name and title, the title of your Keynote, and your mailing address so that we can get you officially registered for the conference. Also, please let me know if you have any special requirements for your Keynote. We will provide the standard set for audiovisuals which is an LCD projector, laptop computer, screen, laser pointer, and microphone.
>
> You are scheduled to present on Tuesday, October 10, 2017 from 8:30 am - 9:00 am. There will be a Presenters' Meeting at 7:30 am on the day of your involvement. The format of the program is discussed at this time. The Presenters' Meeting is also a good time to load your presentation in the session room and check your audiovisuals.
>
> If you'd like to take a look at the preliminary program for the conference, it can be found on our website at https://www.awma.org/climatechange. We will add your Keynote information to the conference website asap and to the final program, which will be released to the public on September 29th.
>
> The conference is being held at the DoubleTree by Hilton Washington DC - Crystal City - 300 Army Navy Drive - Arlington, VA 22202. Please let me know if you have any questions or needs along the way. I look forward to working with you and meeting you at the conference in a few weeks!
>
> Thank you,
>
> Cindy Fontanesi
> Conference & Events Planner
> Air & Waste Management Association
> One Gateway Center, Third Floor
> 420 Fort Duquesne Blvd
> Pittsburgh, PA 15222
> (t) 412-904-6031
> (f)412-232-3450
> Please consider the environment before printing this e-mail
>
>
>
> -----Original Message-----
> From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
> Sent: Thursday, September 14, 2017 9:26 AM
> To: jcmuffat <jcmuffat@yahoo.com>
> Cc: William L. Wehrum <wwehrum@hunton.com>; Cindy Fontanesi <CFontanesi@AWMA.ORG>
> Subject: RE: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Hi Jeff,
> Thank you for the information and I look forward to connecting with Cindy.

> Best,
> Mandy
>
> -----Original Message-----
> From: Jeffry Muffat [mailto:jcmuffat@yahoo.com]
> Sent: Thursday, September 14, 2017 8:08 AM
> To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> Cc: William L. Wehrum <wwehrum@hunton.com>; cfontanesi@awma.org
> Subject: A&WMA's Conference "Finding Common Ground on Climate Change Mitigation and Adaption" Scheduled for October 10th and 11th in Arlington VA
>
> Mandy:
>
> Thank you so much for agreeing to Keynote A&WMA's Conference on Climate Change. The Conference is scheduled for Oct 10-11, 2017 in Arlington, VA and promises to be a great opportunity to exchange meaningful information on the current thinking relative to climate change and how we can mitigate any adverse effects and adapt to the potential consequences. The Association values EPA's thinking and is excited to provide the forum for discussion to our membership and other parties involved in the discussion.
>
> Bill Wehrum said that you planned to check with Administrator Pruitt one last time to see if he was available to Keynote and it would be great if he wanted to speak. However, our intent at this time is to list you in the Program at the Keynoter and then to send out a special mailing/notice announcing Administrator Pruitt as the Keynoter should he decide to speak.
>
> Cindy Fontanesi from A&WMA Headquarters in Pittsburgh will be in touch with you today to work out the details.
>
> Again, thank you so much for agreeing to speak at our upcoming Conference.
>
> Jeff Muffat
> Retired Manager of 3M Environmental Reg Affairs Treasurer of Air & Waste Management Association .
>
>
> ----------
>
> This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
>
https://us1.proofpointessentials.com/index01.php?mod_id=11&mod_option=logitem&mail_id=1505395557-Zfwis8S5ZWjM&r_address=cfontanesi%40awma.org&report=

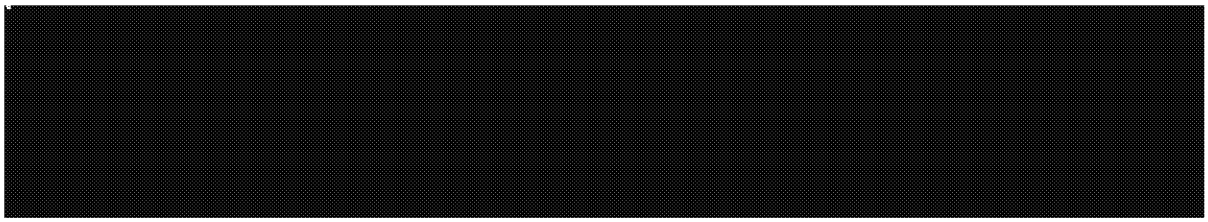
.

This email has been scanned for spam and viruses. Visit the following link to report this email as spam:
https://us1.proofpointessentials.com/index01.php?mod_id&mod_option=gitem&mail_id05418758-QepsfQTnqxHw&r_address◆ontanesi%40awma.org&report=

Message

From: GovTechWorks [info@govtechworks.com]
Sent: 9/29/2017 12:30:52 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Data Strategy Is Essential to Stop Insider Threats | Measuring Cyber Effectiveness | NICE Fix for Cyber Workforce

Display problems? View this newsletter in your browser.



A Long-Term Data Strategy Is Necessary to Stop Insider Threats

Insider threat protection programs accumulate massive storage volumes in order to monitor and track user activity. What data organizations collect – and how long they choose to retain it – depends on its risk tolerance and budget. Read More

Metrics for Measuring Cyber Effectiveness

Worry about cybersecurity means system owners have multiple tools to help protect their organization, but there is no measurement of one tool's effectiveness over another. Read More

NICE Framework Defines Cyber Workforce Needs

Today's shortage of skilled cybersecurity professionals won't end overnight, but the answer to solving the shortage may be here: It's called the National Initiative for Cybersecurity Education Cybersecurity Workforce Framework. By defining a common language to

describe the skills, knowledge and requirements needed to fill each type of cyber job, the framework provides a baseline for understanding which can be shared by employers, educators and workers alike. Read More

What's Popular Now

HIPAA's Threat to Health IT

Health IT systems often focus on complying with data privacy concerns. However, protecting highly sensitive information should be baked into every information system. Read More

New IoT Cyber Standard Eases Security Woes

UL 2900 is the first standard for securing IoT products but it does not absolve users from remaining vigilant against threats. Read More

Secure Software Doesn't Happen by Accident

Modern tools plus old-fashioned discipline yield secure software that's built to stay that way. The key: Catch the flaws before they mushroom into disasters. Read More

From Our Sponsor

Impactful Work. Smart Solutions. Meaningful Careers.
With a career at General Dynamics IT, you will work with leading professionals on solutions that make a difference. Click here to search open jobs.

Upcoming Industry Events

TechNet Europe 2017
Oct. 9-11, 2017

National HUBZone Conference
Oct. 12-13, 2017

Oct. 2017 Breakfast | New Faces, New Places – Innovation
Oct. 19, 2017

More Events

info@govtechworks.com | 703.995.3020 | 3211 Jermantown Rd. Fairfax, VA 22030

GovTechWorks is a GDIT-produced online publication that examines today's public sector IT trends and offers analysis related to the solutions of tomorrow.

Unsubscribe - Manage Your Subscription

Message

From: Alexandra Dapolito Dunn [adunn@ecos.org]
Sent: 9/28/2017 7:37:35 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
CC: Kelly Poole [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=user5e432e30]; Hanson Carolyn [chanson@ecos.org]
Subject: Relevant ECOS Resolutions to Air
Attachments: 10-7 CA Waiver.pdf; 17-5 NAAQS.pdf

Mandy,
Below are two resolutions adopted by ECOS at our recent fall meeting - one on NAAQS and one on the CA Waiver.
I thought they'd be helpful to you and your team.
I understand we'll be on a panel together in Florida on Oct. 10 for EIPF. Hope to see you before then of course!
Best, Alex

Alexandra Dapolito Dunn, Esq.

Executive Director & General Counsel

Environmental Council of the States

50 F Street, NW, Suite 350

Washington, DC 20001

202-266-4929 (T); 202-230-4247 (C);202-266-4937 (F)

adunn@ecos.org; Twitter @ECOStates

See my research: http://ssrn.com/author=1356207

Save the Date! ECOS' Spring Meeting, 3/20-3/22, St. Paul, Minnesota www.ecos.org

ECOS

Resolution 10-7
Approved August 30, 2010
Whitefield, New Hampshire

Renewed September 17, 2013
Arlington, Virginia

Extended to Spring Meeting September 28, 2016
Wheeling, West Virginia

Extended to Fall Meeting April 8, 2017
Washington, D.C.

Revised September 13, 2017
Jackson, Wyoming

As certified by
Alexandra Dapolito Dunn
Executive Director

IN SUPORT OF STATE DISCRETION TO REGULATE POLLUTANTS WITHIN STATE BORDERS, THE RETENTION OF THE CLEAN AIR ACT WAIVER OF CALIFORNIA EMISSIONS STANDARDS, AND THE STATE ADOPTION OF CALIFORNIA STANDARDS

WHEREAS, states are the preferred implementing entities for national environmental regulatory programs for which federal statutes authorize their delegation; and

WHEREAS, states should have the flexibility, consistent with federal law and oversight to determine the best way for their programs to achieve and surpass national minimum standards that enables them to incorporate and integrate their unique geophysical, ecological, social, and economic conditions; and

WHEREAS, states should be the primary enforcement authority for programs delegated to the states; and

WHEREAS, consistent with Constitutional principles, states should be encouraged through flexible federal requirements to develop, pursue, and implement state innovations to effectively and efficiently achieve protections for public health and the environment; and

WHEREAS, states should generally have the ability to set standards that are more stringent or that are broader in scope than federal standards; and

WHEREAS, specifically under section 209(b) of the Clean Air Act (CAA), the United States Environmental Protection Agency (U.S. EPA) shall waive preemption if a qualified state (i.e., California) vehicle emissions standard is at least as protective of public health and welfare as applicable Federal standards; and

WHEREAS, CAA section 177 permits other states to adopt California's vehicle emissions standards; and

WHEREAS, on June 30, 2009, U.S. EPA granted California's request for a waiver of preemption allowing California to enforce its adopted GHG emissions standards and allowing other states to enforce as permissible under CAA section 177 (74 Fed.Reg. 32744 (July 8, 2009)); and

WHEREAS, U.S. EPA's waiver enables California and other states to manage GHG emissions within their state boundaries in a way that best meets each specific states' needs, and recognizes that these reductions are a large part of those states efforts to lower GHG emissions.

NOW, THEREFORE, BE IT RESOLVED THAT THE ENVIRONMENTAL COUNCIL OF THE STATES:

Finds that states must be allowed to exercise their discretion to regulate pollutants within their borders and develop standards at or more stringent than federal regulations, as long as these standards do not conflict with federal law;

Urges the U.S. Congress to retain and not limit: 1) any state's authority to adopt or enforce pollutant standards that are more stringent than the federal standards; 2) California's authority to adopt or enforce emissions standards for any air pollutant from any mobile source; and 2) any state's ability under CAA section 177 to adopt California's vehicle emissions standards.

ECOS

Resolution 17-5
Approved September 13, 2017
Jackson Hole, Wyoming

As certified by
Alexandra Dapolito Dunn
Executive Director

ON NATIONAL AMBIENT AIR QUALITY STANDARDS

WHEREAS, the Clean Air Act (CAA) requires the U.S. EPA to set primary and secondary National Ambient Air Quality Standards (NAAQS) for carbon monoxide, lead, nitrogen dioxide, particulate matter, ozone, and sulfur dioxide (criteria pollutants) that, "allowing an adequate margin of safety," are requisite to protect public health and welfare and confer protections to all citizens equally, and to review and revise the standards, as appropriate, every five years; and

WHEREAS, NAAQS should be science based; and

WHEREAS, in many areas of the country, ambient levels of pollutants have been significantly reduced; and

WHEREAS, many states still are not in attainment; and

WHEREAS, achieving attainment of certain NAAQS "as expeditiously as practicable" is a challenge to some states due to transported air pollution from sources outside of the state's jurisdiction and control; and

WHEREAS, each state has an obligation to design a State Implementation Plan (SIP) that puts the state on a path to timely attainment; and

NOW, THEREFORE, BE IT RESOLVED THAT THE ENVIRONMENTAL COUNCIL OF THE STATES:

Urges U.S. EPA to reassess, as required by the CAA, and revise as appropriate, existing NAAQS in order to ensure that NAAQS reflect current scientific information;

Calls on U.S. EPA to effectively address transported air pollution if and when federal action is needed and appropriate;

Calls on U.S. EPA, in cooperation with states, to develop timely modeling baselines and projections to understand contributions of transported pollutant emissions to states with respect to each NAAQS from sources outside of the state's jurisdiction and control;

Calls on U.S. EPA, in situations where state compliance with NAAQS may be impacted from transported pollutant emissions coming from sources outside of the state's jurisdiction and control, to work cooperatively with states to address the situation;

Urges U.S. EPA to continue to work with states to further improve needed SIP processes and methods for affecting them, and to foster cost-effective and efficient NAAQS implementation strategies;

Calls on U.S. EPA to work with states to focus limited resources on highest priority/problem areas, and, where appropriate, allow states the flexibility to determine the best way for their programs to achieve national minimum standards;

Calls on U.S. EPA to work with the states that have nonattainment on good neighbor SIP obligations under the CAA to implement all reasonable control strategies to achieve timely attainment across the country.

Message

From: ExxonMobil [exxonmobil.dc.vicepresident=exxonmobil.com@mail204.suw14.mcdlv.net]
on behalf of ExxonMobil [exxonmobil.dc.vicepresident@exxonmobil.com]
Sent: 9/25/2017 1:38:51 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: ExxonMobil Expands Methane Emissions Reduction Program

View email in your browser

September 25, 2017

Dear Mandy,

Today, ExxonMobil announced an enhanced program to reduce methane emissions from its production and midstream facilities across the United States.

The program, builds on ExxonMobil's longstanding commitment to emissions management, prioritizes actions at sites operated by subsidiary XTO Energy and includes efforts to develop and deploy new, more efficient technologies to

detect and reduce facility emissions.

"We are implementing an enhanced leak detection and repair program across our production and midstream sites to continually reduce methane emissions, and are also evaluating opportunities to upgrade facilities and improve efficiency at both current and future sites," said XTO president Sara Ortwein. "Our comprehensive initiative is underscored by a technology research and testing effort, and includes personnel training, equipment phase out and facility design improvements."

XTO's efforts also include research conducted with ExxonMobil Upstream Research Company and third-party equipment manufacturers to continue development of more efficient, state-of-the-art equipment to detect, quantify and reduce emissions at production sites. These research efforts build on an extensive portfolio of more than two dozen existing methane research projects and pilots already under way.

As part of the company's efforts to better understand the magnitude and characteristics of oil and gas industry-related methane emissions, ExxonMobil participated in studies conducted by the University of Texas and Environmental Defense Fund.

ExxonMobil remains active in ongoing methane research, including

participation in a methane measurement reconciliation study with the Department of Energy's National Renewable Energy Laboratory, and in supporting research currently underway at Harvard, the University of Texas Energy Initiative, and Stanford University's Natural Gas Initiative.

If you are interested in more information, please feel free to contact me by clicking here or visit the Energy Factor to learn more.

Sincerely,

Gantt Walton
Vice President, Washington Office
Exxon Mobil Corporation

Our mailing address is:
ExxonMobil
2020 K St NW
Washington, DC 20006

Add us to your address book

unsubscribe from this list | update subscription preferences | view email in browser

Message

From: ROBERT.WYMAN@lw.com [ROBERT.WYMAN@lw.com]
Sent: 9/19/2017 3:50:23 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Request for Introductory Meeting - Wednesday, September 27, 4:30 pm

Alex – thank you sincerely. I will send a list of attendees by Monday.

So greatly appreciated.

Bob

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 19, 2017 5:12 AM
To: Wyman, Robert (LA)
Cc: Gunasekara, Mandy
Subject: RE: Request for Introductory Meeting - Wednesday, September 27, 4:30 pm

Morning Bob,

Confirmed for Wednesday, September 27, at 4:30PM EST.

Location: 1200 Pennsylvania Avenue, NW

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg

EPA Contact: For an escort from Security to the meeting call 202-578-5985 or 202-564-3164

Please send me a list of attendees by Monday, September 25, so I can give that to security.

Anything else just let me know.

Best,

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: ROBERT.WYMAN@lw.com [mailto:ROBERT.WYMAN@lw.com]
Sent: Monday, September 18, 2017 2:05 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Request for Introductory Meeting - Wednesday, September 27, 4:30 pm

Good morning, Alex. I am writing to request an introductory meeting with Mandy Gunasekara on the subject of the midterm evaluation and the national greenhouse gas emissions standards for motor vehicles. I make this request on behalf of the ***National Coalition for Advanced Transportation (NCAT)***.

NCAT is a coalition of leading companies that support electric vehicle and other advanced transportation technologies and related infrastructure, including through: energy supply, transmission and distribution; vehicle and component design and manufacturing; charging infrastructure, battery and other energy-storage technology design, production and implementation; infrastructure engineering and construction; and the movement of passengers, goods and services; among other activities. Prior to our meeting, I will provide a list of NCAT attendees.

If possible, we would like to meet with Ms. Gunasekara on Wednesday, September 27, at 4:30 pm. We will be meeting earlier in the afternoon at 3:00 pm with Chris Grundler of OTAQ.

Of course, if 4:30 pm is not a good time, we will do our best to accommodate a different time or date.

Sincere thanks.

Bob

Robert A. Wyman, Jr.
LATHAM & WATKINS LLP
Email: robert.wyman@lw.com

355 South Grand Avenue
Los Angeles, CA 90071-1560
Direct: +1.213.891.8346

555 Eleventh Street, NW
Washington, DC 20004-1304
Direct: +1.202.654.7119

This email may contain material that is confidential, privileged and/or attorney work product for the sole use of the intended recipient. Any review, disclosure, reliance or distribution by others or forwarding without express permission is strictly prohibited. If you are not the intended recipient, please contact the sender and delete all copies including any attachments.

Latham & Watkins LLP or any of its affiliates may monitor electronic communications sent or received by our networks in order to protect our business and verify compliance with our policies and relevant legal requirements.

Latham & Watkins LLP

This email may contain material that is confidential, privileged and/or attorney work product for the sole use of the intended recipient. Any review, disclosure, reliance or distribution by others or forwarding without express permission is strictly prohibited. If you are not the intended recipient, please contact the sender and delete all copies including any attachments.

Latham & Watkins LLP or any of its affiliates may monitor electronic communications sent or received by our networks in order to protect our business and verify compliance with our policies and relevant legal requirements.

Latham & Watkins LLP

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 9/19/2017 3:03:49 PM
To: Geoffrey Moody [GMoody@afpm.org]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: Meeting Time

Geoff - when you arrive please call Mandy at Personal Phone / Ex. 6 as I am in a mandatory meeting. If she doesn't answer you can call me at Personal Phone / Ex. 6 and I'll step out as soon as I can. Appreciate it.

Alex

Sent from my iPhone

On Sep 12, 2017, at 10:43 AM, Geoffrey Moody <GMoody@afpm.org> wrote:

> Thanks Alex. If you could, add Derrick Morgan, AFPM's SVP for Federal Affairs, to the list, but I'm not sure if he'll join.
>
> **From:** Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
> **Sent:** Tuesday, September 12, 2017 10:41 AM
> **To:** Geoffrey Moody <GMoody@afpm.org>
> **Subject:** RE: Meeting Time
>
> Geoff,
>
> Confirmed for Tuesday, September 19th at 11:00AM.
>
> Location: 1200 Pennsylvania Avenue, NW.
>
> Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
> https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg
>
> EPA Contact: For an escort from Security to the meeting call Personal Phone / Ex. 6
>
> Will it be just you, or are others planning to attend as well?
>
> **Alex Dominguez**
> *Policy Analyst to the Senior Advisors to*
> *the Administrator for Air and Water*
> U.S. Environmental Protection Agency
>
> **From:** Gunasekara, Mandy
> **Sent:** Tuesday, September 12, 2017 10:35 AM
> **To:** Geoffrey Moody <GMoody@afpm.org>
> **Cc:** Dominguez, Alexander <dominguez.alexander@epa.gov>
> **Subject:** RE: Meeting Time

Looping in Alex to help firm up remaining logistics. I'll follow-up on RMP.

From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Tuesday, September 12, 2017 10:33 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Meeting Time

Mandy, great talking to you. As discussed, I'm available next Tuesday at 11:00 to meet on various issues.

Thanks,

Geoff Moody
Vice President
Government Relations

American
Fuel & Petrochemical
Manufacturers
1667 K Street NW
Suite 700
Washington, DC 20006
202.457.0480 office
202.552.8489 direct
202.457.0486 fax

gmoody@afpm.org
Learn more about AFPM at afpm.org

Message

From: Rachel Jones [RJones@nam.org]
Sent: 9/27/2017 10:35:53 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Kime, Robin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=7ef7b76087a6475b80fc984ac2dd4497-RKime]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Lovell, Will (William) [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=3b150bb6ade640f68d744fadcb83a73e-Lovell, Wil]
Subject: Re: Meeting Notice

Wonderful. Thanks all!

Rachel Jones
Direct 202-637-3175
Personal Phone / Ex. 6

On Sep 27, 2017, at 6:20 PM, Dominguez, Alexander <dominguez.alexander@epa.gov> wrote:

Hey Rachel – We are all set. Mandy will be there tomorrow.

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Wednesday, September 27, 2017 5:33 PM
To: Lovell, Will (William) <lovell.william@epa.gov>
Cc: Kime, Robin <Kime.Robin@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting Notice

Will—I just spoke with Mandy and she said that she can step in tomorrow morning. So crisis averted!

Alex—Please let me know if you need additional details to those below. I'll be staffing an event this evening but will be available by cell.

Thanks!

Rachel Jones
National Association of Manufacturers
Director, Energy and Resources Policy
E-mail: rjones@nam.org
Direct: (202) 637-3175
Mobile: (804) 380-6542

<image001.png>

From: Lovell, Will (William) [mailto:lovell.william@epa.gov]
Sent: Wednesday, September 27, 2017 5:10 PM

To: Rachel Jones <RJones@nam.org>
Cc: Kime, Robin <Kime.Robin@epa.gov>
Subject: RE: Meeting Notice

Rachel,

I am extremely sorry, but Samantha will not be able to make it tomorrow. Very last minute travel with the Administrator just came up today and we finalized her travel plans recently. Additionally, Brittany is also travelling for work tomorrow so she cannot go in her stead.

If you will still have her, I hope we can arrange for another meeting in the future. I have cc'd the Chief of Staff for the Office of Policy, Robin Kime, to help coordinate such a meeting. Again, I cannot apologize enough for the inconvenience caused by this turn of events.

Sincerely,

Will

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Wednesday, September 27, 2017 5:02 PM
To: Lovell, Will (William) <lovell.william@epa.gov>
Subject: RE: Meeting Notice

All good for in the morning?

Rachel Jones
(202) 637-3175

From: Lovell, Will (William) [mailto:lovell.william@epa.gov]
Sent: Friday, September 22, 2017 10:37 AM
To: Rachel Jones <RJones@nam.org>
Subject: RE: Meeting Notice

Thank you, Rachel!

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Friday, September 22, 2017 10:34 AM
To: Lovell, Will (William) <lovell.william@epa.gov>
Subject: Meeting Notice

I wanted to send you a copy. Please let me know if you guys need anything. Thanks!

Rachel Jones
(202) 637-3175

From: Ross Eisenberg, NAM [mailto:Ross.E.Eisenberg@nam.org]
Sent: Wednesday, September 20, 2017 11:36 AM
To: Rachel Jones <RJones@nam.org>
Subject: Meeting Notice - Energy Forum, September 28 at the NAM

Energy Forum

A Joint Project of ACC, AFPM, API, INGAA, NAM, and the U.S. Chamber

Dear Energy and Natural Resources Committee Members:

Our next Energy Forum will take place on September 28, 2017 and will feature Samantha Dravis, Associate Administrator for the Office of Policy at the U.S. Environmental Protection Agency.

Attendance is in-person only, and *seating will be limited*. If you would like to attend, please RSVP here.

Thursday, September 28, 2017
10:00 am – 11:00 am
National Association of Manufacturers
733 10th Street, Suite 700
Washington, DC 20001

We will continue to hold these events every two weeks, rotating speakers among the federal agencies and relevant congressional committees of jurisdiction. We hope this will be a valuable way to obtain up-to-date information from the key players making policy in Washington. As a reminder: the meetings will be in-person attendance only, closed-press and off-the-record.

We look forward to seeing you on September 28th.

Thanks,
Ross

Ross Eisenberg
Vice President, Energy and Resources Policy
National Association of Manufacturers
Direct: 202.637.3173
Mobile: 703.517.1655
Email: reisenberg@nam.org

To no longer receive invites to NAM's Energy Forums, click here.

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 9/18/2017 4:52:37 PM
To: Ceglia, Lisa (CWDC) [Lisa.Ceglia@smiths.com]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting request

Great – thank you so much for the quick response.

Confirmed for Wednesday, September 27th at 12:00PM.

Location: 1200 Pennsylvania Avenue, NW

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg

EPA Contact: For an escort from Security to the meeting call me at Personal Phone / Ex. 6 or 202-564-3164

Anything else just let me know.

Best,
Alex

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 18, 2017 12:40 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Meeting request

That would be perfect, thanks. I'll send along all names shortly. Thank you.

Sent from my Verizon, Samsung Galaxy smartphone

-------- Original message --------
From: "Dominguez, Alexander" <dominguez.alexander@epa.gov>
Date: 9/18/17 12:28 PM (GMT-05:00)
To: "Ceglia, Lisa (CWDC)" <Lisa.Ceglia@smiths.com>
Cc: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

Lisa – Would 12:00PM on Wednesday the 27th work for you all? Additionally, if I can just get the list of attendees for security that would be great.

Best,
Alex

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Gunasekara, Mandy
Sent: Monday, September 18, 2017 10:18 AM
To: Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>
Cc: Lyons, Troy <lyons.troy@epa.gov>; Jackson, Ryan <jackson.ryan@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Meeting request

Alex, can you help organize the logistics for this meeting please?

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 18, 2017 9:38 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Lyons, Troy <lyons.troy@epa.gov>; Jackson, Ryan <jackson.ryan@epa.gov>
Subject: Re: Meeting request

Good morning, greetings from Myrtle Beach. I had to come recover after witnessing yet another awful Bills game. Hope y'all had a great weekend. Just wanted to check in if you had a time that would work on the 27th? We currently have a few requests pending, but wanted to work around you. Our only conflict as of now is at 2:00.

Thanks again for agreeing to do this. See you next week.

Lisa

PS- Troy, Baltimore D got me 20 fantasy points- wahoo!

Sent from my iPad

On Sep 11, 2017, at 4:28 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Troy – you are still very special.
> Lisa! I can't wait to catch up and look forward to the discussion with John.
>
> ---
>
> **From:** Lyons, Troy
> **Sent:** Monday, September 11, 2017 4:20 PM
> **To:** Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>; Jackson, Ryan <jackson.ryan@epa.gov>
> **Cc:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** RE: Meeting request
>
> Here I thought I was special....
>
> ---
>
> **From:** Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
> **Sent:** Monday, September 11, 2017 3:27 PM
> **To:** Jackson, Ryan <jackson.ryan@epa.gov>; Lyons, Troy <lyons.troy@epa.gov>

Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

Hi Mandy—Ryan speaks the truth ☺. Hope you are well. Let me know the best times for you all and we'll get it on the schedule.

Thanks so much!

Lisa

From: Jackson, Ryan [mailto:jackson.ryan@epa.gov]
Sent: Monday, September 11, 2017 3:24 PM
To: Ceglia, Lisa (CWDC) <Lisa.Ceglia@smiths.com>; Lyons, Troy <lyons.troy@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting request

We would be happy to. I'll include Mandy your other actual favorite person to contribute too. We'll figure out the best time.

From: Ceglia, Lisa (CWDC) [mailto:Lisa.Ceglia@smiths.com]
Sent: Monday, September 11, 2017 3:07 PM
To: Jackson, Ryan <jackson.ryan@epa.gov>; Lyons, Troy <lyons.troy@epa.gov>
Subject: Meeting request

Hello!!! If it isn't two of my favorite people, EVER. Now that I've adequately flattered you..

John Crane, our oil and gas supplier division, is bring John Donatiello, VP of Global products to town September 27th. John has never really done the DC meeting tour with us and we would like to take him to all the places of interest. Of course, I thought of you both. Would you have time on the 27th to discuss the Methane re-proposal and the future of other rules and regulations you see coming? Really, just any issues you think he may find fascinating.

I included the link to John Crane below. We are the manufacturer of mechanical seals, suppling sealing device technology to oil and gas, chemical, water and other facilities.

Happy to discuss in further detail prior to the meeting. Please let me know a time that will work for you and we will do our best to accommodate.

Thank you, thank you!

Lisa

Lisa M. Ceglia
Vice President
Government Relations
Smiths Group
425 Third Street, SW, Ste. 875
Washington, DC 20024
Phone: 202-777-8453
Cell: Personal Phone / Ex. 6

PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.

****
CAUTION: THIS MESSAGE ORIGINATED FROM THE PUBLIC INTERNET AND WAS NOT SENT FROM THE SMITHS EMAIL SYSTEM
****
PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.

PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.
PROPRIETARY: This e-mail contains proprietary information some or all of which may be legally privileged. It is intended for the recipient only. If an addressing or transmission error has misdirected this e-mail, please notify the author by replying to this e-mail. If you are not the intended recipient you must not use, disclose, distribute, copy, print, or rely on this e-mail.

Message

From: Dominguez, Alexander [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=5CED433B4EF54171864ED98A36CB7A5F-DOMINGUEZ,]
Sent: 9/18/2017 4:48:02 PM
To: Geoffrey Moody [GMoody@afpm.org]
CC: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: Meeting Time

Great. Appreciate the flexibility and looking forward to it.

From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Monday, September 18, 2017 12:45 PM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting Time

That works for me

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Monday, September 18, 2017 12:36 PM
To: Geoffrey Moody <GMoody@afpm.org>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Meeting Time

Geoff – Would you be able to move the meeting tomorrow from 11:00 to 11:30? Mandy has a 10:30 tomorrow that cannot be rescheduled and I have a feeling it may run over.

Alex

From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Tuesday, September 12, 2017 10:42 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Meeting Time

Thanks Alex. If you could, add Derrick Morgan, AFPM's SVP for Federal Affairs, to the list, but I'm not sure if he'll join.

From: Dominguez, Alexander [mailto:dominguez.alexander@epa.gov]
Sent: Tuesday, September 12, 2017 10:41 AM
To: Geoffrey Moody <GMoody@afpm.org>
Subject: RE: Meeting Time

Geoff,

Confirmed for Tuesday, September 19th at 11:00AM.

Location: 1200 Pennsylvania Avenue, NW.

Directions: Please use the William Jefferson Clinton North Entrance located on your right as you exit the Federal Triangle Metro Station.
https://www.epa.gov/sites/production/files/2013-08/federaltrianglemap5.jpg

EPA Contact: For an escort from Security to the meeting call Personal Phone / Ex. 6 or 202-564-3164.

Will it be just you, or are others planning to attend as well?

Alex Dominguez
Policy Analyst to the Senior Advisors to
the Administrator for Air and Water
U.S. Environmental Protection Agency

From: Gunasekara, Mandy
Sent: Tuesday, September 12, 2017 10:35 AM
To: Geoffrey Moody <GMoody@afpm.org>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: RE: Meeting Time

Looping in Alex to help firm up remaining logistics. I'll follow-up on RMP.

From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Tuesday, September 12, 2017 10:33 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Meeting Time

Mandy, great talking to you. As discussed, I'm available next Tuesday at 11:00 to meet on various issues.

Thanks,

Geoff Moody
Vice President
Government Relations

American
Fuel & Petrochemical
Manufacturers
1667 K Street NW
Suite 700
Washington, DC 20006
202.457.0480 office
202.552.8489 direct
202.457.0486 fax

gmoody@afpm.org
Learn more about AFPM at afpm.org

Message

From: Davis, Patrick [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=7FCA02D1EC544FBBBD6FB2E7674E06B2-DAVIS, PATR]
Sent: 9/12/2017 3:22:24 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Geoffrey Moody [GMoody@afpm.org]
CC: Darwin, Veronica [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=bc98aaf2f15a466baede3dab0e27a35e-Darwin, Ver]; Brooks, Becky [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=6f369a2ef33e4a87af349210a3915a57-BBrooks]; Hill, Teresa [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=fa5cb0ccf6b24276a9a0d898d3e04c87-thill02]
Subject: RE: Meeting Time

Hi Geoff,

Mandy, thank you for the introduction. Please coordinate a time to meet with Becky Brooks and Teresa Hill, copied here.

Thanks,

Patrick Davis
Environmental Protection Agency
Deputy Assistant Administrator, Office of Land and Emergency Management
202-564-3103 office
Personal Phone / Ex. 6 cell

Information sent to this email address may be subject to FOIA.

From: Gunasekara, Mandy
Sent: Tuesday, September 12, 2017 11:11 AM
To: Geoffrey Moody <GMoody@afpm.org>
Cc: Darwin, Veronica <darwin.veronica@epa.gov>; Davis, Patrick <davis.patrick@epa.gov>
Subject: RE: Meeting Time

Geoff,
Great catching up this morning. I've cc'd Veronica Darwin and Patrick Davis who are the point people for anything RMP related. I hope you all can find a time to connect.
Best,
Mandy

From: Geoffrey Moody [mailto:GMoody@afpm.org]
Sent: Tuesday, September 12, 2017 10:33 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Meeting Time

Mandy, great talking to you. As discussed, I'm available next Tuesday at 11:00 to meet on various issues.

Thanks,

Geoff Moody

Vice President
Government Relations

American
Fuel & Petrochemical
Manufacturers
1667 K Street NW
Suite 700
Washington, DC 20006
202.457.0480 office
202.552.8489 direct
202.457.0486 fax

gmoody@afpm.org
Learn more about AFPM at afpm.org

Message

From: Smith, Robert L. [RLSmithII@Venable.com]
Sent: 5/12/2017 6:45:08 PM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Gunasekara, Surya [Surya@mail.house.gov]
Subject: RE: Get on the Bus

Mandy -- per our chat last weekend, do you have a minute to talk on an issue? Thanks. 202.344.4077

--rob

From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Monday, May 08, 2017 10:49 PM
To: Smith, Robert L. <RLSmithII@Venable.com>; Gunasekara, Surya <Surya@mail.house.gov>
Subject: RE: Get on the Bus

Personal Matters / Ex. 6

From: Smith, Robert L. [mailto:RLSmithII@Venable.com]
Sent: Monday, May 8, 2017 10:47 PM
To: Gunasekara, Surya <Surya@mail.house.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Get on the Bus

Yes! Please send home address.

From: Gunasekara, Surya <Surya@mail.house.gov>
Sent: Monday, May 8, 2017 11:38:14 AM
To: Smith, Robert L.
Cc: Mandy Gunasekara
Subject: RE: Get on the Bus

In. 2 adults, 2 kids.

From: Smith, Robert L. [mailto:RLSmithII@Venable.com]
Sent: Sunday, May 07, 2017 11:32 AM
Subject: Get on the Bus

All:

Formal invite to follow but please let me know if you can join us to celebrate our daughter Daley's first birthday Personal Matters / Ex. 6

Personal Matters / Ex. 6

No gifts please....lemme know! --rob

Rob Smith | Venable LLP
t 202.344.4077 | f 202.344.8300 | m 202.258.5486
600 Massachusetts Ave, NW, Washington , DC 20001

rlsmith@venable.com | www.Venable.com

****
This electronic mail transmission may contain confidential or privileged information. If you believe you have received this message in error, please notify the sender by reply transmission and delete the message without copying or disclosing it.
****

****
This electronic mail transmission may contain confidential or privileged information. If you believe you have received this message in error, please notify the sender by reply transmission and delete the message without copying or disclosing it.
****

****
This electronic mail transmission may contain confidential or privileged information. If you believe you have received this message in error, please notify the sender by reply transmission and delete the message without copying or disclosing it.
****

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 11/3/2017 5:10:23 PM
To: Eule, Stephen [SEule@USChamber.com]
Subject: RE: Bonn

Yes – I get there on the 12th (Sunday) and leave on the 16th (Thursday). I'll reach out once I get there. Safe travels and see you there!

From: Eule, Stephen [mailto:SEule@USChamber.com]
Sent: Friday, November 3, 2017 12:49 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: Bonn

Mandy: I understand you'll be in Bonn for COP-23. I plan on arriving Wednesday the 8th and departing Wednesday the 15th (that's about as much as I can stand). Let's try to get together while over there. Cheers. Steve

Stephen Eule
Vice President
Global Energy Institute
U.S. Chamber of Commerce
202 463 5654
seule@uschamber.com
http://www.globalenergyinstitute.org/

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 11/6/2017 6:37:29 PM
To: Horner, Elizabeth (EPW) [Elizabeth_Horner@epw.senate.gov]
Subject: fact sheet
Attachments: Fact Sheet for Final Ozone Designations Round.docx

See attached. Great catching up! Good luck with the forthcoming hearings and vote.

Mandy M. Gunasekara
Principal Deputy Assistant Administrator
Office of Air and Radiation
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 11/1/2017 7:30:09 PM
To: surya@sectionvii.com
Subject: FW: Cooler Heads Coalition invitation and meeting reminder

FYI

From: Myron Ebell [mailto:Myron.Ebell@cei.org]
Sent: Wednesday, November 1, 2017 2:13 PM
To: Myron Ebell <Myron.Ebell@cei.org>
Subject: Cooler Heads Coalition invitation and meeting reminder

Reminder: the Cooler Heads Coalition will hold its next regular monthly strategy meeting on Monday, 13th November, beginning at 12 noon at CEI, 1310 L Street, N. W., Seventh Floor. Please e-mail or ring me at 331-2256 with agenda items or questions.

As tax reform legislation takes shape in the next few weeks, our carbon tax event is timely. I have pasted competing lead articles from this morning's E & E Daily and ClimateWire (also published by E & E) below the invitation. Our three panelists all have compelling arguments and data to show how economically destructive, politically destructive, and environmentally useless a carbon tax would be. I hope you can make it.

Competitive Enterprise Institute
Institute for Energy Research
and
The Cooler Heads Coalition

invite you to

Carbon Tax Follies

with opening remarks by

Representative Bill Flores (R-Texas)

and a panel discussion with

Marlo Lewis, Ph. D.
Senior Fellow, Competitive Enterprise Institute

James Lucier
Managing Director, Capital Alpha

Robert Murphy, Ph. D.
Senior Economist, Institute for Energy Research

2:30 – 3:30 PM
Thursday, November 2, 2017
Room 2322, Rayburn House Office Building
(refreshments provided)

Promoters of taxes on carbon dioxide emissions are trying to attract support from conservatives by claiming that such taxes are a free market response to global warming. Promoters claim that CO2 taxes can be revenue neutral, can be a huge new source of additional government revenues, and that the revenues can be returned as a dividend to consumers. It is also claimed that taxing emissions is a cost-effective way to lower those emissions, will create more jobs than are lost, and will even provide a boost to the economy.

After opening remarks by Rep. Bill Flores, three experts will debunk these claims and discuss the real economic and political effects of CO2 taxes. Jim Lucier will also discuss a just-published economic analysis of recent carbon tax proposals. There will be time for Q&A with the panelists.

RSVP Here

For purposes of congressional ethics rules, this is a widely attended event.

Questions? Please contact Taylor Barkley at taylor.barkley@cei.org

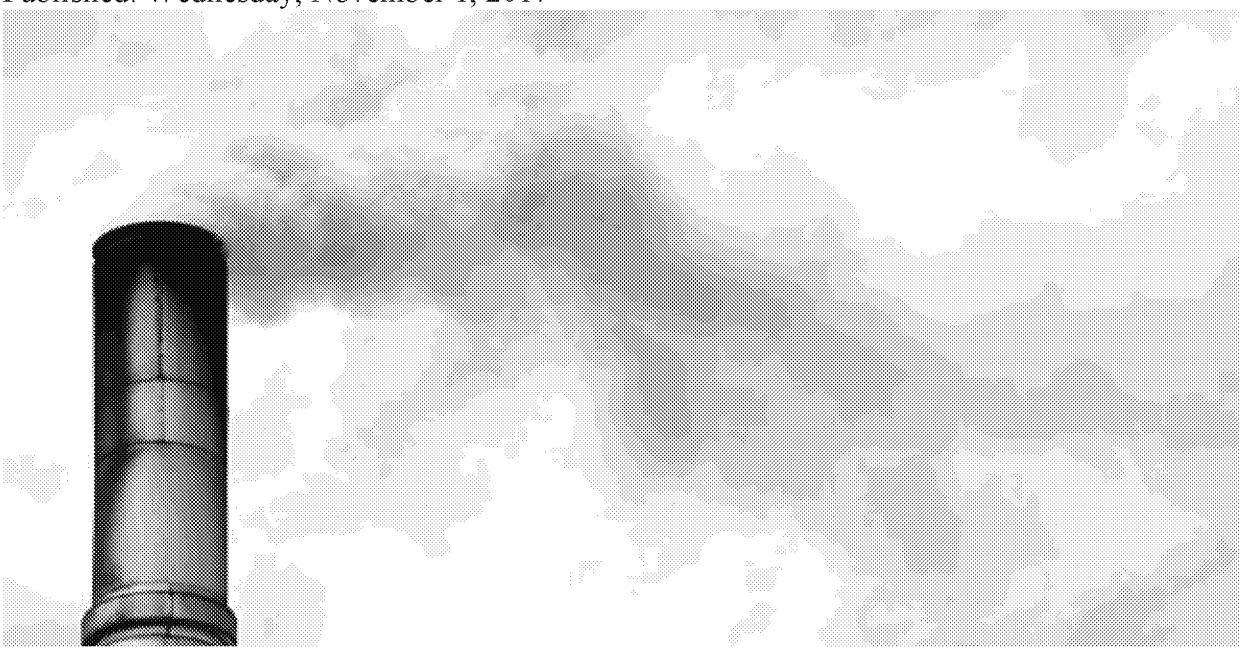
E & E Daily

CLIMATE

Meet the 'eco right' pushing for a carbon fee

Arianna Skibell, E&E News reporter

Published: Wednesday, November 1, 2017



Despite the political headwinds, some lawmakers continue working toward a carbon tax. Ian Barbour/Flickr

Over the summer, Democratic Sens. Sheldon Whitehouse of Rhode Island and Brian Schatz of Hawaii introduced legislation to instate a carbon tax to reduce greenhouse gas emissions and said they were looking for a Republican co-sponsor.

A glimmer of hope for them emerged when Republican Sen. Lindsey Graham of South Carolina publicly endorsed the plan in September.

But after a spate of hurricanes, a dozen wildfires and mass flooding, many weeks later there has been virtually no public progress on carbon legislation.

"Let's see, let's see, let's see," Whitehouse told E&E News yesterday. "Well, what I can say is what Lindsey Graham has said publicly, which is that he is working with me and looking at that bill. He has announced nothing further, and I have nothing to announce."

Jerry Taylor, a prominent libertarian in favor of a carbon fee, said the lack of movement on the Hill could mean a carbon tax window is opening.

"The main evidence for that read of the law of the land is the opponents of carbon taxation are mobilized and engaged, and they wouldn't be if this were not a live issue," he said. "When you see opponents to a proposed idea mobilized and actively engaged in the fight, it tells you the fight is farther along than you think."

For the last couple of months, grass-roots conservative groups opposed to a carbon fee — the Club for Growth and the Competitive Enterprise Institute, for example — have been on high alert, Taylor said.

Whitehouse said that indeed contrary to popular opinion, there are a growing number of Republicans, conservatives and libertarians who openly support pricing carbon. They're just not on the Hill, yet.

"There is considerable Republican support for a revenue-neutral border adjustable carbon fee outside of the political crucible of Congress, and indeed, it's really the only solution that has generated any significant Republican support," said Whitehouse.

Bob Inglis, a former Republican congressman from South Carolina who famously reversed his climate skeptic stance, agreed there is growing movement on the right to address global warming.

"This space has been dominated by folks on the environmental left," he said. "They think they have an open door to Republicans, but they really don't. So we're developing what we call the 'eco right.' It's a balance to the environmental left."

Think tanks

Niskanen Center

The Niskanen Center was founded in 2014 by Taylor and is predominantly focused on Capitol Hill outreach.

Prior to founding the center, Taylor spent 23 years to advance the Cato Institute's libertarian agenda. His job was to change hearts and minds on issues like free markets, limited government and climate change.

He worked to demonstrate that the economic toll of reducing carbon emissions would not outweigh the potential benefits. But as he spent more time with climate science and economics, his views began to shift (*Greenwire*, June 16).

Taylor, a vocal proponent of a carbon tax, said he is seeing movement on that front.

"We're meeting not only with the usual suspects, like members of [Florida Republican Rep.] Carlos Curbelo's Climate Solutions Caucus, but also with Republican members outside that coalition, and what we're finding is there is a great deal of sympathy towards action on climate change and a lot of interest in carbon taxation," he said. "But there is uncertainty about the political road from here to there."

Taylor said Republican members are not worried about the merits of the carbon fee structure but rather what is often called "safe passage" politically.

Taylor's preferred legislation would levy carbon taxes at the point of production, use proceeds to offset revenue losses from tax cuts, rebate a portion of the revenue to poor households, eliminate U.S. EPA's authority to regulate greenhouse gas emissions and eliminate green energy subsidies, among other measures.

Taylor said he believes his ideas have merit not only because they allow the market to work but also because climate change is real and imposes risk.

"And it's not conservative to act as if risk does not exist and play dice with the planet," he said.

R Street Institute

In 2012, the Heartland Institute, one of the leading groups questioning global warming science, launched a digital billboard campaign featuring Ted Kaczynski, the "Unabomber."

The ad read, "I still believe in global warming, do you?"

Following the campaign, some Heartland members working on insurance issues decided it was time to break off and start their own outfit that took climate change seriously.

"We still have a friendly relationship with [Heartland]," said Josiah Neeley, senior fellow, energy policy director and Southwest region chief for the R Street Institute. But as insurance brokers, R Street employees understood risk, he said.

"If you're dealing in insurance, you need to be able to take climate change seriously. Because it's not realistic if you're talking about sea-level rise, storms, droughts, floods, you name it," Neeley said.

R Street, founded in June 2012, is a think tank that promotes free markets and limited government. The group supports a carbon tax. Neeley said R Street applies conservative values and principles to address the warming planet.

"The most common or strongest objection that we get from folks when we talk about this stuff is the idea that it's not politically realistic in one way or another," he said.

"Being skeptical about government implementation I think is a fair point," Neeley said, "but there are a lot of things that we advocate for that would be pretty major changes to policy, and knowing politicians are flawed vessels I don't think that means that we should just give up."

Thought leaders

Climate Leadership Council

The Climate Leadership Council, founded earlier this year by Washington, D.C., think tank veteran Ted Halstead, is known around town for its high-profile members, including former New York Mayor Michael Bloomberg, scientist Stephen Hawking, famed economist Larry Summers and others.

The council also includes corporate entities like Exxon Mobil Corp., BP PLC and Royal Dutch Shell PLC, and nongovernmental organizations like the Nature Conservancy and Conservation International.

In February, the council formally launched with the publication of its manifesto: "The Conservative Case for Carbon Dividends," authored by eight GOP statesmen.

They included Republican heavyweights James Baker III, who served under both Presidents George H.W. Bush and Reagan, and George Shultz, who served under both Reagan and President Nixon.

The proposal, which they presented to the White House, includes four main policy goals: a gradually increasing carbon tax, border carbon adjustments, carbon dividends for all taxpayers and significant regulatory rollbacks (*Greenwire*, Feb. 8).

Jill Sigal, the executive vice president who served in President George W. Bush's administration as assistant secretary of Energy for congressional and intergovernmental affairs, said the plan is free market, pro-growth, pro-environment and pro-jobs.

"We think that our proposal is a conservative solution to reducing emissions, while not negatively impacting the U.S. economy," she said. "We believe that the U.S. needs to take action on a federal level to reduce climate emissions."

At the Yale Climate Conference this year, Baker said that the proposal should appeal to people regardless of their stance on warming. He called the measure an insurance policy, saying the risk is too great to not do something.

Sigal said she senses climate engagement on a variety of Republican fronts, from the business community to the House Climate Solutions Caucus.

She said council members have frequented the Hill in recent months to take meetings with both House and Senate members about their proposal.

"We've had some interesting and great meetings these last few months," she said. "We're getting very good reception on the Hill."

Alliance for Market Solutions

The Alliance for Market Solutions is led by Alex Flint, a former member of President Trump's transition team who previously worked as senior vice president of governmental affairs at the Nuclear Energy Institute, and by fellow NEI alumnus Chris Carter.

The board of advisers for AMS brings together Republicans with experience in private equity, investment banking and energy consulting.

They include Vicky Bailey, who served as an assistant secretary at the Department of Energy under the second Bush administration and as a Republican member of the Federal Energy Regulatory Commission; John Rowe, chairman emeritus of Exelon Corp.; and former Sen. Mel Martinez (R-Fla.).

"We think there are a significant number of Republican members of Congress who agree that Republicans need to engage on climate change, and we've been quite pleased with their willingness to talk with us about what a Republican position should be," Flint said.

He stressed his group is "just" Republican. He's not interested in being bipartisan.

The alliance aims to "educate conservative policymakers on the benefits of market-oriented solutions to one of America's most pressing economic challenges: advancing clean energy and reducing carbon pollution," a mission statement said.

Unlike the Climate Leadership Council, AMS is not pushing a dividend model. "Using the proceeds of a carbon tax to pay a rebate or dividend would produce no additional economic growth or jobs," AMS states on its website.

The group advocates using the revenue to cut corporate or individual income taxes, estimating each American family would benefit by nearly $3,000 annually.

Targeting the public

RepublicEn

RepublicEn Executive Director Inglis launched the Energy and Enterprise Initiative at George Mason University in July 2012. The group works to educate conservatives, libertarians and pragmatists about climate change and a carbon fee.

"We're engaging with conservatives in the heartland and presenting broad solutions to climate change. The most immediate solution is a revenue-neutral border adjustable carbon tax," Inglis said.

"Mostly what needs to happen is conservative members of Congress need to hear from their constituents a readiness to engage in the competition of ideas of how to solve climate change," he said. "We're out gathering that constituency so elected officials will feel comfortable leading."

For six years, Inglis said he thought climate change was nonsense. "I didn't know anything about it, but I knew Al Gore was for it," he said.

When he ran for Congress again in 2004, his son approached him. "He said, 'Dad, I'll vote for you, but you're going to clean up your act on the environment,'" Inglis recounted.

Inglis said it was a three-step process, the final of which was an encounter with a scientist named Scott Heron on a trip to look at the Great Barrier Reef.

"We shared a worldview because he was worshiping God in what he was showing me. Told me about conservation changes he's making in his life," Inglis said.

When he returned to Congress, he introduced a revenue-neutral border adjustment tax as an alternative to cap and trade, both of which went nowhere.

"When I got tossed out of Congress, I started working on this effort," Inglis said in reference to RepublicEn. He said his group, made up of over 3,800 members, is finding success with young conservatives and conservatives of faith.

"It's harder with their parents, and it's really pretty hard with their grandparents," he said. "The challenge is the grandparents vote more often. The thing I'm supremely confident of is we are going to win, but will we win soon enough to head off the worst consequences of climate change?"

Citizens' Climate Lobby conservative caucus

While the Citizens' Climate Lobby is a nonpartisan group, its member are mostly left-leaning volunteers. Still, the group contains a conservative caucus, which is growing.

CCL targets Republican members of Congress and urges them to join the bipartisan House Climate Solutions Caucus (*E&E Daily*, Sept. 6).

Since the caucus's inception in 2016, CCL and others have had unprecedented success pushing GOP politicians to join. The grass-roots advocacy organization is angling for the caucus to take up a carbon fee and dividend approach to curb emissions.

While members of the House "Noah's Ark" group, which adds Republicans and Democrats in pairs, have co-sponsored a number of climate-related bills, like renewable energy tax credits, they have yet to broach a carbon tax. Still, activists are encouraged by the growing membership, which reached 60 this year.

Also notable is Citizens for Responsible Energy Solutions, which is a grass-roots campaign engaging with Republican policymakers for cleaner power.

https://www.eenews.net/eedaily/2017/11/01/stories/1060065267

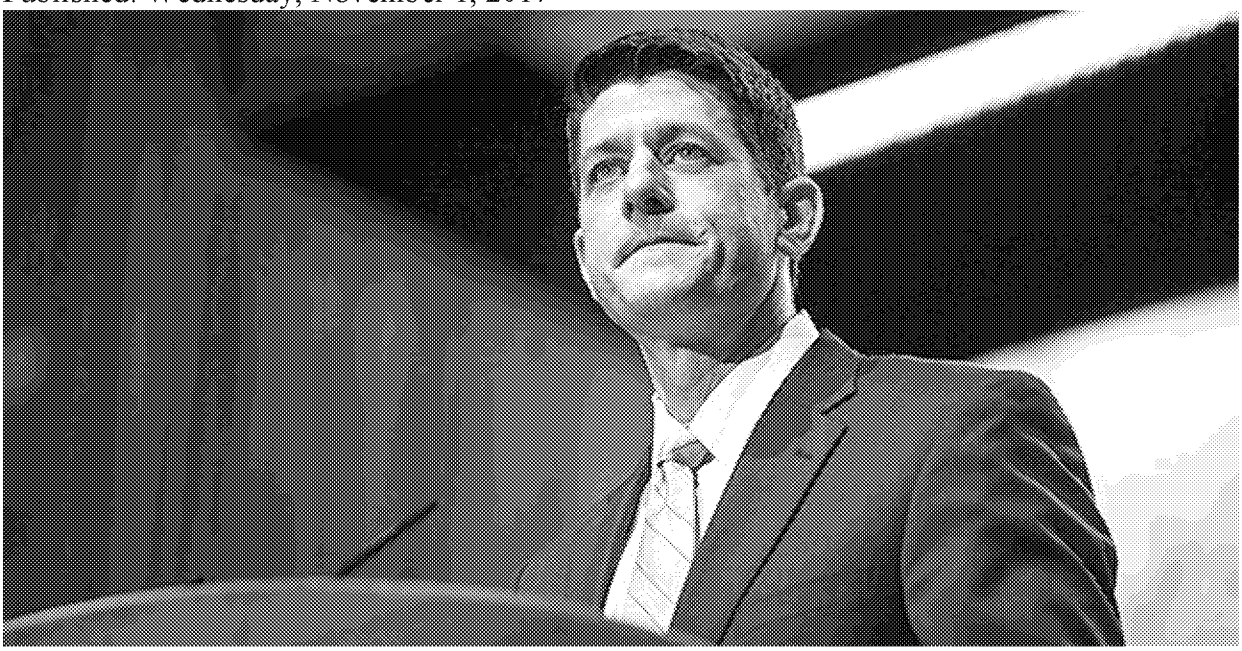
ClimateWire

POLITICS

A carbon tax would raise cash, but GOP isn't going there

Josh Kurtz, E&E News reporter

Published: Wednesday, November 1, 2017



Supporters of taxing carbon emissions say it could happen during overall tax reform. House Speaker Paul Ryan (R-Wis.) is not a fan. Gage Skidmore/Flickr

As Congress takes on the ambitious and arduous task of rewriting the U.S. tax code, it seems like prime time for advocates of a carbon tax to aggressively promote the idea.

They're not.

Carbon tax advocates — especially those in Republican-aligned groups that have been slowly building their case for a carbon tax — recognize that they've still got a major sales job to do. As they consider the politics of the moment, most carbon tax proponents concede that they'll probably be relegated to the sidelines as the big debate over tax reform commences, although advocates hope it'll enter the debate eventually.

"We are very much in the early stages of our work," said Greg Bertelsen, senior vice president of the Climate Leadership Council, the organization put together by former secretaries of State James Baker and George Shultz, both Republicans, and other former top government officials and business leaders to promote a carbon tax and other remedies to address climate change.

"This is a major policy proposal that Mr. Baker and Mr. Shultz and others have proposed," Bertelsen said. "Like any major proposal, it's going to take time to build support and educate policymakers."

There is zero evidence that Republican congressional leaders, who will be driving the debate over tax reform in tandem with the Trump administration and are anxious for their first major legislative victory of the year, have any interest in addressing a carbon tax proposal right now.

"I wouldn't see too many Republicans jumping on this," said Steve Valk, a spokesman for the Citizens' Climate Lobby, a group that has worked to push climate issues to the forefront in Congress.

GOP leaders need near-unanimity in their caucuses to get any tax reform proposal through and are seeking to avoid complications and distractions.

"You have to pick your battles," said Valk, whose organization has helped bring about the creation of the 60-member House Climate Solutions Caucus, which is equally divided between Republicans and Democrats. "The Republicans really want to pass a tax bill, and to do so, they have to all be on the same page."

But talk of a carbon tax may not be completely absent from the tax reform debate. Although House leaders are optimistically aiming to pass their version of the bill before Thanksgiving, the overall legislative process could take considerably longer, and there may be opportunities to inject the climate tax proposal into the broader discussion.

Rep. John Larson (D-Conn.), a senior member of the tax-writing House Ways and Means Committee and the lone Democrat on Ways and Means who also belongs to the Climate Solutions Caucus, told E&E News last week that he plans to introduce a "Pollution Tax Amendment" when the panel takes up the GOP reform bill in the next few weeks (*Climatewire*, Oct. 24). While by Larson's own admission the amendment is unlikely to get very far, it could make some Ways and Means Republicans uncomfortable — and it may also open the door to some discussion about the concept.

"If there's an opportunity to share our proposal with lawmakers — members of the committee or otherwise — we'll take it," Bertelsen said.

But Valk said he doesn't expect the idea to get much traction in Ways and Means unless Rep. Carlos Curbelo (R-Fla.), a member of the panel and co-chairman of the Climate Solutions Caucus, embraces it.

Curbelo's office did not respond to a request for comment this week. Neither did spokesmen for two other Ways and Means Republicans who are members of the climate caucus, Reps. Dave Reichert of Washington and Patrick Meehan of Pennsylvania. The caucus itself has not advanced any proposals to address climate change in its short life span.

Valk said Curbelo seems likely to back the Republican tax plan and isn't expected to try to attach a carbon tax amendment to it.

"I think he's going to keep his powder dry for legislation down the road," Valk predicted. "I think his plan is to be a good team player" during the tax reform debate.

Even if a Democratic proposal on the carbon tax doesn't get far in committee initially, former Rep. Bob Inglis (R-S.C.), executive director of republicEn, a group offering free-enterprise solutions to tackle climate change, sees additional opportunities for introducing the issue during the reform debate.

The House Republican tax plan, he said, features so many tax cuts that would dramatically expand the federal deficit that lawmakers may be looking for solutions to plug the budget hole. A revenue-neutral carbon tax will be one option for tax-writers to consider.

"Adding a carbon tax is a way to do tax reform and balance the budget at the same time," Inglis said yesterday. "The idea is to tax pollution, not profits. It's completely consistent with what conservatives have long advocated."

The key, the former lawmaker said, will be to persuade Republicans concerned about exploding the deficit to break with President Trump and GOP congressional leaders.

"Whether this is going to happen, I don't know," he said. "It depends on whether budget hawks balk at a revenue-negative proposal. If they do, then you have to search for revenue."

Democrats are already warning about the consequences of growing the federal deficit.

In the Democrats' weekly address released Saturday, which amounted to a "pre-buttal" of the GOP reform plan, Sen. Ben Cardin (D-Md.), a member of the tax-writing Finance Committee, said Republicans have "formulated a tax scheme that they admit will add $1.5 trillion to our deficit while putting Medicare and Medicaid at risk. And their plan hurts middle- and low-income working families while providing huge tax cuts for the wealthiest Americans."

Democratic criticism is unlikely to sway Republicans committed to cutting taxes. But an analysis by the nonpartisan Concord Coalition, which has long fought to reduce government deficits, could carry a little more political pop.

"Faced with the prospect of steep tax cuts, a number of Republicans in the House and Senate seem to have forgotten their frequently voiced concerns about deficits," Steve Winn wrote this week. "It is important to remember — as many economists across the political spectrum have noted in recent days — that tax cuts, while they can provide some short-term boost for the economy, do not 'pay for themselves.'"

Right now, there is little chatter about any senator attempting to attach a carbon tax amendment to the tax package when it hits the Finance Committee. Senate aides said the priority of Democratic leaders now is to home in on the message that the Republican plan hurts middle-class families, and Democratic lawmakers may be reluctant to advance any proposal that can be construed as a tax increase in the context of the broader reform debate.

As if to buttress the point, the Senate Democratic Policy and Communications Committee has scheduled a hearing for this afternoon titled "Who Pays for the GOP's Trillion Dollar Tax Cut? How Families, Seniors and the Middle Class Are Hit Hardest." The session will feature testimony from national policy experts and stakeholders in Kansas, where a massive tax cut in 2012 crippled government services and stifled economic growth, in the Democrats' view.

Still, the broad tax debate could ultimately open up discussions about energy taxes and incentives and their overarching policy implications (*E&E Daily*, Oct. 27). And stand-alone Democratic bills promoting a carbon tax have been introduced in the House and Senate, though with no action scheduled so far.

"We're making progress," Inglis said.

https://www.eenews.net/climatewire/2017/11/01/stories/1060065223

Myron Ebell
Director, Center for Energy and Environment
Competitive Enterprise Institute
1310 L Street, N. W., Seventh Floor
Washington, DC 20005, USA
Tel direct: (202) 331-2256
Tel mobile: (202) 320-6685
E-mail: Myron.Ebell@cei.org
Stop continental drift!

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/17/2017 3:16:22 AM
To: Jeff Speaks [jeff@jbsgov.com]
Subject: Re: Thank you

Jeff,
Thank you for coming in today. I enjoyed meeting you and the discussion. I look forward to continuing to work through the issues discussed today.
Best,
Mandy

Sent from my iPhone

On Oct 16, 2017, at 4:33 PM, Jeff Speaks <jeff@jbsgov.com> wrote:

> Mandy:
>
> Thank you again for your time earlier today and very much appreciated the opportunity to present some info and concerns from the perspective of dealers like Worldwide Equipment. We'll be working to put together additional information per your and Erik's questions and points but please let me know if there's anything additional you need in the interim. Enjoyed meeting you and look forward to visiting with you again soon.
>
> Jeff
>
> *Jeff Speaks*
> *JBS Communications*
> *149 Cherokee Park*
> *Lexington, Kentucky 40503*
> *(859) 494-2681*
> *jeff@jbsgov.com*

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/22/2017 7:31:21 PM
To: unsubscribe-utkyuil2aqdkjip2d-CBFF4FE6@cmail19.com
Subject: Unsubscribe

iOS Mail sent this email to unsubscribe from the message "Tribune-Review: An End To EPA's 'Sue & Settle' " .

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/6/2017 8:07:41 PM
To: surya.gunasekara Personal Email / Ex. 6
Subject: White House Info

See this link: I've printed out 7 copies https://events.whitehouse.gov/form/boardingPass?Id=a2et0000000AFcy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/19/2017 12:36:40 AM
To: pgray@crowell.com
CC: Kelly, Albert [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=08576e43795149e5a3f9669726dd044c-Kelly, Albe]
Subject: E Connect for Superfund

Peter,

It was very nice meeting you tonight at the ELI dinner. Based on our conversation, I'm connecting you with Kell Kelly (CC'd) who is leading the Superfund reform efforts underway at EPA.

Kell, Peter works at Crowell and has an interest in touching base regarding your work. I believe it would be good for you both to connect.

Best,
Mandy

Sent from my iPhone

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/20/2017 12:34:34 AM
To: Jillian Melchior [jillian.melchior@wsj.com]
Subject: Re: Introduction

Personal Phone / Ex. 6

I look forward to talking then.

Sent from my iPhone

On Oct 19, 2017, at 8:01 PM, Jillian Melchior <jillian.melchior@wsj.com> wrote:

> That works! What's the best number to reach you?
>
> On Thu, Oct 19, 2017 at 7:12 PM Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>
> > Yes – 8 am would work for me. Does that work for you?
> >
> > **From:** Melchior, Jillian [mailto:jillian.melchior@wsj.com]
> > **Sent:** Thursday, October 19, 2017 5:56 PM
> > **To:** Abboud, Michael <abboud.michael@epa.gov>
> > **Cc:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bowman, Liz <Bowman.Liz@epa.gov>
> > **Subject:** Re: Introduction
> >
> > Hi, Mandy,
> >
> > Good to meet you, and I appreciate your willingness to talk.
> >
> > I've actually got a dinner meeting scheduled for tonight that I can't miss, but would any time tomorrow morning work for you? Early is fine by me if that's best.
> >
> > Kind regards,
> >
> > Jillian
> >
> > Jillian Kay Melchior
> >
> > Editorial Page Writer

The Wall Street Journal

212-416-3608

jillian.melchior@wsj.com

On Thu, Oct 19, 2017 at 5:46 PM, Abboud, Michael <abboud.michael@epa.gov> wrote:

> Jillian, I'm connecting you with Mandy Gunasekara who is our lead on all RFS issues. She said she would be able to talk to you on background, but not until around 8:30 tonight. I'll leave it to everyone here to figure out logisitics as I'll be on a flight at that time.

--

Jillian Kay Melchior
Editorial Page Writer
The Wall Street Journal
212-416-3608
jillian.melchior@wsj.com

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/9/2017 7:56:40 PM
To: Chrissy Harbin [CHarbin@afphq.org]
Subject: RE: AFP Praises Clean Power Plan Repeal

Chrissy,
Great to hear from you. Thank you for passing along the statement! Hope you are well.
Best,
Mandy

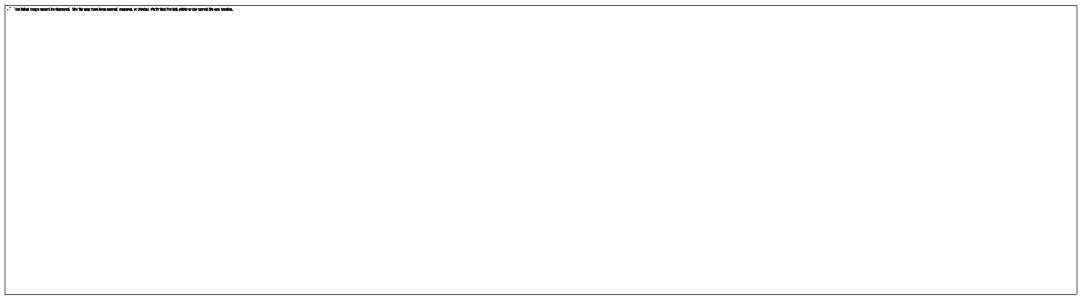
From: Chrissy Harbin [mailto:CHarbin@afphq.org]
Sent: Monday, October 9, 2017 3:54 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: FW: AFP Praises Clean Power Plan Repeal

Hi Mandy,
In advance of tomorrow's announcement, our official statement is forwarded below and online here, FYI -
- https://americansforprosperity.org/afp-praises-clean-power-plan-repeal/

Chrissy Harbin | Vice President of External Affairs | Americans for Prosperity
M: (202) 560-1691 | E: charbin@afphq.org | T: @ChrissyHarbin

From: AFP Media <Media@afphq.org>
Date: Monday, October 9, 2017 at 1:21 PM
To: Chrissy Harbin <CHarbin@afphq.org>
Subject: AFP Praises Clean Power Plan Repeal

This is a major promise kept by the Trump administration.



NEWS RELEASE

FOR IMMEDIATE RELEASE: October 9, 2017

CONTACT: Chris Neefus, CNeefus@afphq.org

AFP Praises Clean Power Plan Repeal

Grassroots organization has opposed CPP for years

Arlington, Va. – Americans for Prosperity commended EPA Administrator Scott Pruitt today following his announcement that he will sign a proposed rule to repeal the Clean Power Plan (CPP) Tuesday. The group has long fought to protect Americans' access to affordable, reliable energy, opposing harmful regulations like the CPP that force dramatically higher costs on American households.

Under this job-killing Obama-era energy rule, states would be pushed into draconian emissions cuts, forced to switch to costlier forms of energy which could ultimately cost consumers as much as $33 billion. AFP has consistently opposed harmful regulations like the CPP which would drive up energy costs for hard-working families, crush small businesses and expand federal powers with virtually no environmental benefit.

Americans for Prosperity had previously invested in grassroots efforts to oppose the Clean Power Plan and supported legal efforts from state attorneys general to halt its implementation. The group also recently issued a statement of support for Scott Pruitt's nomination to the EPA after he had been a leader in opposing the policy.

AFP Vice President of External Affairs Chrissy Harbin had the following to say:

> *"This is a welcome departure from the Washington-first, Americans-last approach that characterized energy and environmental policy under the previous administration. The Clean Power Plan (CPP) was an overreach of executive power; President Obama's attempt to implement an agenda so radical that he could not get it passed through Congress when his party controlled both chambers. It's great to see President Trump and EPA Administrator Pruitt rein in this sweeping mandate that forces states to slash their carbon emissions and switch to costlier forms of energy.*
>
> *We are encouraged to see such decisive action by the Trump administration to offer relief from this legally dubious, drastic rule that posed such a significant threat to electricity prices and economic growth. This is a major promise kept by the Trump administration. Repealing the Clean Power Plan will restore these energy decisions to duly elected state officials, and Americans who need reliable energy to run their households and businesses. We look forward to continuing to work with policymakers in seeking policies that promote economic growth and protect Americans' access to affordable and reliable energy solutions."*

The grassroots group has made unwinding overregulation a centerpiece of their Reform America 2017 agenda, a set of legislative priorities that the group will advocate for this year.

For comprehensive information about AFP's steps to get Americans relief from over-burdensome regulations in the energy sector and beyond, or for an interview, contact Chris Neefus at CNeefus@afphq.org.

View online

BACKGROUND

AFP Has Led the Charge Against EPA Overreach For Years

2017: The Media are Missing Trump's Much-Needed Regulatory Relief, by Christine Harbin (Washington Examiner)

2017: AFP Executive Order on Energy Regulations is Right Direction (Release)

2017: Regulatory Reform Gets Spotlight in Washington, by Christine Harbin (Morning Consult)

2017: LETTER: AFP Supports Full, Fair Consideration of Scott Pruitt for EPA Administrator

2016: Trump Administration Will Bring Huge Reform to Energy and Environment, by Christine Harbin (Morning Consult)

2016: AFP Joins Coalition Asking Lawmakers To Overturn Ozone Regulations That Would Place "A Tremendous Burden On Communities Across America." "A coalition of 60 conservative groups is asking lawmakers to overturn the Obama administration's new ozone pollution rule and change the law under which it was written. 'The ozone regulation places a tremendous burden on communities across America,' the groups wrote to the heads of the House and Senate committees with jurisdiction over the EPA. … The coalition includes some big names such as Americans for Prosperity and FreedomWorks, along with state and local groups and others with smaller footprints." (Timothy Cama, "Conservative Groups Target Ozone Law In Push For Rule's Rollback," The Hill, 5/9/16)

2016: AFP Praises SCOTUS Decision to Halt President's Clean Power Plan

2015: AFP Sends Press Release In Support Of The EPA Overregulation Of Rural Americans Act.

2015: AFP Sends Press Release Urging States To Push Back against EPA's "Clean Power" Overreach.

2014: AFP Sends Letter To State Legislatures Urging Them To Resist EPA's Clean Power Plan. "A coalition of conservative groups is pressing states to "fiercely resist" the Environmental Protection Agency's carbon pollution rule for existing power plants. The broad array of organizations sent a letter to state legislators, attorneys general and governors, calling on them to resist the administration's proposal at every turn and to refuse to help the EPA along its process. … 'We urge you to fiercely resist any attempt to appease the EPA's demands. EPA's so-called Clean Power Plan (CPP) is illegitimate, an affront to both federalism and the separation of powers,' the letter states. The letter — signed by Heritage Action, and the -backed Americans for Prosperity and American Commitment — doesn't mince words, arguing the EPA can't control 'its appetite for power' and that the proposal can't be implemented in any 'feasible or responsible' way." (Laura Barron-Lopez, "Conservatives Urge States To 'Fiercely Resist' EPA's Climate Rule," The Hill, 12/5/14)

2014: New Obama EPA Water Rules Set to Drown Property Rights, Economic Growth

2014: Grassroots to Congress: Stop the EPA Power Grab!

2014: AFP Sends Press Release Denouncing EPA's Carbon Regulation Rules That Would "Cost Billions Of Dollars And Hundreds Of Thousands of Jobs."

For further information or an interview, reach Chris Neefus at* CNeefus@afphq.org *or (703) 517-4504.

View online

Americans for Prosperity (AFP) exists to recruit, educate, and mobilize citizens in support of the policies and goals of a free society at the local, state, and federal level, helping every American live their dream – especially the least fortunate. AFP has more than 3.2 million activists across the nation, a local infrastructure that includes 36 state chapters, and has received financial support from more than 100,000 Americans in all 50 states. For more information, visit www.AmericansForProsperity.org

###

If you would rather not receive future communications from Americans for Prosperity, let us know by clicking here.
Americans for Prosperity, 1310 N. Courthouse Rd., Arlington, VA 22201 United States

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 10/9/2017 5:05:04 PM
To: rnolan@nma.org
Subject: Ceremony

Hey Rich, can you give me a call when you have a second? Personal Phone / Ex. 6

Sent from my iPhone

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/25/2017 2:49:23 PM
To: Vivian Aucoin [Vivian.Aucoin@LA.GOV]
Subject: RE: AAPCA Fall Meeting

Vivian,
Thank you for the note and it was a pleasure meeting you. I have no doubt I'll be reaching out. I also heard good news on the RH SIP from Sam Coleman on Friday, so I'm happy to hear that is progressing forward. Feel free to reach out as well. The best number is my work cell: Personal Phone / Ex. 6
Best,
Mandy

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Monday, September 25, 2017 10:43 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: AAPCA Fall Meeting

Greetings!

It was such a pleasure to meet you last week and I wanted to thank you once again for participating in the AAPCA Fall Conference in Raleigh, NC. It was good to hear the Administrator's ideals and to know what our path forward will entail. I look forward to working with this administration.

I also wanted to thank you for your time concerning the Regional Haze SIP issues that we have encountered. I believe that the state has put together a SIP that not only approvable but one that will protect the visibility at the Breton Wilderness Class I area. If there is anything we can do to help you through the maze in which the SIP world exists, please do not hesitate to call.

Have a great week!

Vivian H. Aucoin
Environmental Scientist Manager
Office of Environmental Assessment, Air Planning Division
225-219-3482
vivian.aucoin@la.gov

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/27/2017 9:05:49 PM
To: Andrews, Joshua L. [Joshua.Andrews@FaegreBD.com]
CC: dominguez.alex@epa.gov
Subject: Re: Renewable Fuel Standard

Phone would be best. Alex, please coordinate for a good time.

Sent from my iPhone

On Sep 27, 2017, at 4:27 PM, Andrews, Joshua L. <Joshua.Andrews@FaegreBD.com> wrote:

> Mandy/Alex, good afternoon.
>
> I am contacting you to see if you might have time to touch base regarding the Renewable Fuel Standard. There's obviously a lot of activity around the program and I'd be interested in getting your thoughts. Happy to jump on the phone if you have some time available.
>
> Thank you for your consideration!
>
> Joshua L. Andrews
> *Director*
> joshua.andrews@FaegreBD.com Download vCard
> D: +1 202 589 2819
>
> **Faegre Baker Daniels Consulting**
> 1050 K Street NW | Suite 400 | Washington, DC 20001, USA

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/29/2017 4:58:44 PM
To: Hilary Moffett [moffetth@api.org]
Subject: Re: NSPS Delay

Thank you for the update!

Sent from my iPhone

On Sep 29, 2017, at 11:57 AM, Hilary Moffett <moffetth@api.org> wrote:

Hi Mandy!

Happy Friday. I just wanted to let you know that I've reached out to OMB to request a meeting on the two-year delay for NSPS. We do not have it scheduled yet, but hope to go in as early as next week to discuss the importance of the stay.

Personal Matters / Ex. 6

Cheers,
Hilary

Hilary Moffett
Director, Federal Relations
American Petroleum Institute
202-682-8040 (desk)
612-710-8696 (cell)
MoffettH@api.org

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/13/2017 6:12:12 PM
To: Palumbo, David [dpalumbo@usbr.gov]
Subject: RE: Call

No worries!

From: Palumbo, David [mailto:dpalumbo@usbr.gov]
Sent: Wednesday, September 13, 2017 2:10 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Call

Hi Mandy:

Sorry for the delay. I am making my way out of the building and to the airport.

I will call in a moment.

Thanks,

David

On Wed, Sep 13, 2017 at 2:08 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hi David,
>
> I believe we have a call at 2 pm, however I don't have a number. What is the best number to reach you? Alternatively, I can be reached at my desk at 202-564-2314.
>
> Best,
>
> Mandy
>
> **Mandy M. Gunasekara**
>
> Senior Policy Advisor for Office of Air and Radiation
>
> Office of the Administrator
>
> US Environmental Protection Agency

Appointment

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/11/2017 8:00:53 PM
To: Wehrum, William L. [wwehrum@hunton.com]

Subject: Canceled: Nomination Hearing
Location: EPW

Start: 9/20/2017 4:00:00 AM
End: 9/21/2017 4:00:00 AM
Show Time As: Free

Importance: High

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/13/2017 5:13:16 PM
To: Miller, Becky L [Becky.L.Miller@p66.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Phillips 66 R&D Efforts

Hi Becky,
Thank you for the outreach. Sept. 29 at 3 pm would work best. I'm ccing Alex to firm up any remaining logistics.
Best,
Mandy

From: Miller, Becky L [mailto:Becky.L.Miller@p66.com]
Sent: Wednesday, September 13, 2017 10:40 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Phillips 66 R&D Efforts

Good morning, Ms. Gunasekara. At the request of Dale Thanjan, I am contacting you to schedule a conference call with Dr. Merl Lindstrom, Vice President, Technology and Dr. Randy Heald, Manager, Sustainability Research. Listed below are dates/times (CT) currently open on their schedules. Please let me know if any of these dates would work with your schedule. Thank you.

Sept. 22	**3:00 PM CT**
Sept. 26	**8:00 AM or 1:00 PM**
Sept. 28	**3:00 PM**
Sept. 29	**3:00 PM**
Oct. 2	**10:00 AM**
Oct. 3	**anytime between 8-10:00 AM, and 2-4:00 PM**

Becky Miller
Administrative Assistant, Technology

O: 918.977.6747 | F: 918.977.7146
RF-02-257 | Phillips 66 Research Center | Bartlesville, OK 74003-6670
Phillips 66

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/7/2017 11:20:54 PM
To: surya.gunasekara Personal Address / Ex. 6
Subject: Fwd: ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION

Sent from my iPhone

Begin forwarded message:

From: "EPA Press Office" <press@epa.gov>
Date: September 7, 2017 at 6:49:46 PM EDT
To: "Gunasekara.Mandy@epa.gov" <Gunasekara.Mandy@epa.gov>
Subject: ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION
Reply-To: press@epa.gov

U.S. ENVIRONMENTAL PROTECTION AGENCY
NEWS RELEASE
WWW.EPA.GOV/NEWSROOM

ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION

Wehrum Nominated to Head Air and Radiation Office

WASHINGTON (September 7, 2017) Today, President Donald J. Trump announced his intention to nominate Bill Wehrum to serve as EPA Assistant Administrator for the Office of Air and Radiation (OAR). Mr. Wehrum has a long history of public service, and previously served as EPA's acting assistant administrator for Air and Radiation from 2005 to 2007 and as EPA's principal deputy assistant administrator and counsel to the assistant administrator for Air and Radiation. He is currently partner and head of the Administrative Law Group at Hunton & Williams LLP where his practice focuses on air quality issues. Mr. Wehrum's career includes over 31 years working in the environmental field through engineering, legal practice, and administrative duties.

His nomination is receiving high accolades from environmental leaders across the country:

Sean Alteri, director, Kentucky Division for Air Quality and 2017 president of the Association of Air Pollution Control Agencies: "Considering his education and experience as a chemical engineer and an environmental attorney, Mr. Wehrum will be

well-positioned to provide clear, concise direction to address the many diverse, complex air quality issues. As a student of the Clean Air Act, Mr. Wehrum's knowledge and experience will greatly benefit EPA, state, and local air pollution control agencies. We look forward to working with Mr. Wehrum and EPA's senior leadership to improve air quality in Kentucky and throughout our nation. The Kentucky Division for Air Quality supports Mr. Wehrum's nomination to serve as the assistant administrator of EPA's Office of Air and Radiation."

John Cruden, president-elect of the American College of Environmental Lawyers and assistant attorney general, Environment and Natural Resources Division, U.S. Department of Justice (12/2014-1/2017): "I have worked with Bill Wehrum while he was a senior official at EPA during the Bush Administration, and have followed his impressive career in private practice. I believe he is committed to achieving clean air for all citizens and carefully following sound and current science."

Jeff Holmstead, assistant administrator, Office of Air and Radiation, EPA (2001 - 2005): "Bill is committed to the goals of the Clean Air Act and to the rule of law. He is also a person of the highest integrity. I am confident that, within the framework established by Congress, he will work to protect public health and the environment while at the same time pursuing regulatory reforms that will reduce unnecessary regulatory burdens. Truly, there is no better person to serve as the assistant administrator of EPA's Office of Air and Radiation."

Marcus Peacock, EPA deputy administrator (08/2005 - 01/2009): "Bill Wehrum's understanding of the Clean Air Act may be second to none. His desire to pull up his sleeves and actually make the Clean Air Act work as a practical matter is second to none."

Clint Woods, executive director, Association of Air Pollution Control Agencies: "Through his comprehensive knowledge of the law and experience in the federal government, Bill possesses the background to manage challenging Clean Air Act issues at U.S. EPA and help continue the tremendous air quality progress that has been achieved in our country over the last several decades. Under his leadership, the Office of Air and Radiation will be well-situated to pursue a back-to-basics agenda grounded in cooperative federalism."

<!--[if !mso]--> Visit The EPA's Newsroom <!--[endif]-->

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue Northwest
Washington, D.C. 20004

Unsubscribe

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/21/2017 6:25:24 PM
To: Miles Keogh [mkeogh@4cleanair.org]
Subject: RE: AAPCA / twitter

Miles,
I appreciate the heads up (I was not aware) and more importantly am absolutely committed to developing a very constructive relationship with you and NACAA. I've worked with the association before and will continue to do so regardless of any characterization from 3rd party groups. I'm interested in discussing these issues with thought leaders and experienced state regulators both of which make up a core part of NACAA. When the logistics work out, you know I'll be there to discuss these issues in person!
Best,
Mandy

From: Miles Keogh [mailto:mkeogh@4cleanair.org]
Sent: Thursday, September 21, 2017 1:09 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: AAPCA / twitter

Mandy, I saw on twitter that NRDC or EDF or someone had taken a swipe at your speaking at AAPCA this week when you weren't able to speak with NACAA last Spring. I wanted to let you know we had nothing to do with that, my staff and I haven't spoken to anyone on staff at those orgs nor said anything but positive things about our recent communications – heck, I just exchanged good emails with Clint this morning. I think it's unfair they did that, and I hope your interaction with the agencies was productive. I'm counting on ours to be productive going forward too, and I won't play games with you and your team like that.

My best, Miles

Miles Keogh
Executive Director
National Association of Clean Air Agencies
444 North Capitol Street, NW, Suite 307
Washington, DC 20001
Phone: (202) 624-7864
mkeogh@4cleanair.org
www.4cleanair.org

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/7/2017 10:51:42 PM
To: Wehrum, William L. [wwehrum@hunton.com]
Subject: FW: ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION

Yay!

From: EPA Press Office [mailto:press=epa.gov@cmail19.com] **On Behalf Of** EPA Press Office
Sent: Thursday, September 7, 2017 6:50 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION

U.S. ENVIRONMENTAL PROTECTION AGENCY
NEWS RELEASE
WWW.EPA.GOV/NEWSROOM

ENVIRONMENTAL LEADERS PRAISE BILL WEHRUM EPA NOMINATION

Wehrum Nominated to Head Air and Radiation Office

WASHINGTON (September 7, 2017) Today, President Donald J. Trump announced his intention to nominate Bill Wehrum to serve as EPA Assistant Administrator for the Office of Air and Radiation (OAR). Mr. Wehrum has a long history of public service, and previously served as EPA's acting assistant administrator for Air and Radiation from 2005 to 2007 and as EPA's principal deputy assistant administrator and counsel to the assistant administrator for Air and Radiation. He is currently partner and head of the Administrative Law Group at Hunton & Williams LLP where his practice focuses on air quality issues. Mr. Wehrum's career includes over 31 years working in the environmental field through engineering, legal practice, and administrative duties.

His nomination is receiving high accolades from environmental leaders across the country:

Sean Alteri, director, Kentucky Division for Air Quality and 2017 president of the Association of Air Pollution Control Agencies*:* "Considering his education and experience as a chemical engineer and an environmental attorney, Mr. Wehrum will be well-positioned to provide clear, concise direction to address the many diverse, complex air quality issues. As a student of the Clean Air Act, Mr. Wehrum's knowledge and experience will greatly benefit EPA, state, and local air pollution control

agencies. We look forward to working with Mr. Wehrum and EPA's senior leadership to improve air quality in Kentucky and throughout our nation. The Kentucky Division for Air Quality supports Mr. Wehrum's nomination to serve as the assistant administrator of EPA's Office of Air and Radiation."

John Cruden, president-elect of the American College of Environmental Lawyers and assistant attorney general, Environment and Natural Resources Division, U.S. Department of Justice (12/2014-1/2017): "I have worked with Bill Wehrum while he was a senior official at EPA during the Bush Administration, and have followed his impressive career in private practice. I believe he is committed to achieving clean air for all citizens and carefully following sound and current science."

Jeff Holmstead, assistant administrator, Office of Air and Radiation, EPA (2001 - 2005): "Bill is committed to the goals of the Clean Air Act and to the rule of law. He is also a person of the highest integrity. I am confident that, within the framework established by Congress, he will work to protect public health and the environment while at the same time pursuing regulatory reforms that will reduce unnecessary regulatory burdens. Truly, there is no better person to serve as the assistant administrator of EPA's Office of Air and Radiation."

Marcus Peacock, EPA deputy administrator (08/2005 - 01/2009): "Bill Wehrum's understanding of the Clean Air Act may be second to none. His desire to pull up his sleeves and actually make the Clean Air Act work as a practical matter is second to none."

Clint Woods, executive director, Association of Air Pollution Control Agencies: "Through his comprehensive knowledge of the law and experience in the federal government, Bill possesses the background to manage challenging Clean Air Act issues at U.S. EPA and help continue the tremendous air quality progress that has been achieved in our country over the last several decades. Under his leadership, the Office of Air and Radiation will be well-situated to pursue a back-to-basics agenda grounded in cooperative federalism."

Visit The EPA's Newsroom

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue Northwest
Washington, D C. 20004

Unsubscribe

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/26/2017 3:28:08 AM
To: Andrew.Oldham@gov.texas.gov
Subject: Fuel Waiver
Attachments: Harvey Fuel Waiver 8.25.2017 signed.pdf; ATT00001.txt

Hey Andy,

I want to make sure you have seen the attached fuel Waiver from Administrator Pruitt. Feel free to reach out with any questions and follow up. Team EPA is ready to help however we can.

Mandy

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 9/11/2017 3:20:18 PM
To: demulling@eli.org
Subject: RSVP

Please add me to the list of attendees for the ELI Award Dinner.
Best,
Mandy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/21/2017 2:16:45 PM
To: Jason Eberstein [jeberstein@namanow.org]
Subject: RE: Quick call?

Sorry we cut out. Call when you have good service. (202) 564-2314.

-----Original Message-----
From: Jason Eberstein [mailto:jeberstein@namanow.org]
Sent: Monday, August 21, 2017 9:37 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Quick call?

Do you have 5/10 mins to briefly chat on the phone?

Gracias!

JE

Jason Eberstein
Director, State & Federal Government Affairs NAMA
301.537.4114

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/11/2017 12:28:38 PM
To: Joe Depew [jdepew@fitzgeraldtrucksales.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Call

Yes - 11 am Eastern. You can call my direct (202) 564-2314.

-----Original Message-----
From: Joe Depew [mailto:jdepew@fitzgeraldtrucksales.com]
Sent: Friday, August 11, 2017 8:17 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Call

Also just confirming 11:00 eastern?

> On Aug 11, 2017, at 7:11 AM, Joe DePew <jdepew@fitzgeraldtrucksales.com> wrote:
>
> 11:00 would be great. What number shall I call you on?
>
> Thanks and have a great weekend,
> Joe
>
>> On Aug 11, 2017, at 8:05 AM, "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov> wrote:
>>
>> Joe- happy to chat. Monday will work. I'm free at 9 am or 11-do either of those times work for you?
>>
>> Sent from my iPhone
>>
>>> On Aug 11, 2017, at 7:53 AM, Joe DePew <jdepew@fitzgeraldtrucksales.com> wrote:
>>>
>>> Mandy,
>>>
>>> Hope you are well. Do you have a few minutes for a call today or Monday?
>>>
>>> Thanks,
>>> Joe

Appointment

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/14/2017 6:52:09 PM
To: Craig.Butler@epa.ohio.gov

Subject: Meeting Forward Notification: SO2 discussion

Start: 8/14/2017 7:00:00 PM
End: 8/14/2017 7:30:00 PM
Show Time As: Busy

Your meeting was forwarded

Gunasekara, Mandy has forwarded your meeting request to additional people.

Meeting

SO2 discussion

Meeting Time

Monday, August 14, 2017 4:00 PM - Monday, August 14, 2017 4:30 PM

Recipients

Wagner, Kenneth,Dravis, Samantha,Koerber, Mike,Page, Steve,DeMocker, Jim

All times listed are in the following time zone: (UTC-05:00) Eastern Time (US & Canada)

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/1/2017 3:15:10 AM
To: Shepherd, Ray [rayshepherd@peabodyenergy.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Re: Lazard intro

Hi Ray,

I am happy to touch base. I am looping in Alex who can help find a time that works.

Best,
Mandy

Sent from my iPhone

> On Jul 31, 2017, at 6:42 PM, Shepherd, Ray <rayshepherd@peabodyenergy.com> wrote:
>
> Mandy--
>
> Hope you are doing well. Sorry we missed you on Friday. Overall it was a good meeting, but I was wondering if you could find 20 minutes to talk to the Lazard guys who are aggressively shopping NGS. Your alternative B could save new owners $1B. I'd love to have a brief conference call with them to discuss. Anyway we can make that happen this week? Much appreciated.
>
> Sent from my iPhone
>
> _____
>
> E-mail Disclaimer:
> The information contained in this e-mail, and in any accompanying documents, may constitute confidential and/or legally privileged information. The information is intended only for use by the designated recipient. If you are not the intended recipient (or responsible for the delivery of the message to the intended recipient), you are hereby notified that any dissemination, distribution, copying, or other use of, or taking of any action in reliance on this e-mail is strictly prohibited. If you have received this email communication in error, please notify the sender immediately and delete the message from your system.
>

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/7/2017 8:11:23 PM
To: Moore, Andrew [Andrew.Moore@mail.house.gov]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Re: Glider Kits

I'm in Canada until Wednesday. I'll set up a time either Thursday or Friday. Alex, can you please set up a quick call with Andrew?

Sent from my iPhone

On Aug 7, 2017, at 11:21 AM, Moore, Andrew <Andrew.Moore@mail.house.gov> wrote:

> Mandy –
>
> Tried your number and was not able to get through. When can we touch base?
>
> Best,
>
> **A.J. Moore**
> Senior Legislative Assistant
> Office of Congressman David Young (IA-03)
> 202-225-5476
>
> ---
>
> **From:** Moore, Andrew
> **Sent:** Thursday, August 03, 2017 2:20 PM
> **To:** 'Gunasekara, Mandy'
> **Subject:** RE: Glider Kits
>
> Thanks for the quick response. Let's just plan on tomorrow afternoon. Is there a specific time that will work best for you?
>
> AJ
>
> ---
>
> **From:** Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
> **Sent:** Thursday, August 03, 2017 1:19 PM
> **To:** Moore, Andrew
> **Subject:** Re: Glider Kits
>
> AJ, I just tried you. I have about 20 minutes before my plane takes off. 202-306-8538 is my cell.
>
> If I don't catch you now, Ill try to connect at some point tomorrow afternoon.
>
> Best,
> Mandy
>
> Sent from my iPhone
>
> On Aug 3, 2017, at 9:47 AM, Moore, Andrew <Andrew.Moore@mail.house.gov> wrote:

Mandy –

My boss spoke with Ryan Jackson last week regarding Glider Kits. Your name was given as the contact. Hoping I can get a quick call in with you sometime this week for an update. Please let me know when you are available.

Best,

A.J. Moore
Senior Legislative Assistant
Office of Congressman David Young (IA-03)
202-225-5476

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/27/2017 6:35:52 PM
To: Sandra Dunphy [sandra.dunphy@weaver.com]
Subject: RE: Available Resource

Hi Sandra,

It was great meeting you and I appreciate you sharing your expertise with me. Have no doubt that I'll be calling soon!

Best,
Mandy

From: Sandra Dunphy [mailto:sandra.dunphy@weaver.com]
Sent: Thursday, July 27, 2017 1:35 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Available Resource

Hi Mandy,

I just wanted to send you a quick note to say thank you for taking the time to meet with me and Mike McAdams yesterday.

If you ever need any industry information related to fuels programs please feel free to reach out to me as a resource. I'd be happy to help. As I mentioned yesterday, we are quite knowledgeable about, but neutral on, almost all fuel-related issues (other than those few that may directly impact Weaver) due to the variety of clients that we serve. I think that puts us into a somewhat unique position to opine independently.

Again, thank you for your time. It was a real pleasure to meet you!

Sandra

weaver

Sandra Dunphy
Weaver
Director
Energy Compliance Services
aka RINderella
D: 832.320.3218 **M:** 281.610.4750
sandra.dunphy@weaver.com
ICE IM: sdunphy

24 Greenway Plaza, Suite 1800
Houston, TX 77046
P: 713.850.8787 **F:** 713.850.1673
View Bio and VCard

Locations Throughout Texas | weaver.com
An Independent Member of Baker Tilly International

DISCLAIMER: This e-mail message is intended only for the personal use of the recipient (s) named above. This message is confidential and may be privileged. If you are not an intended recipient, you may not review, copy, or distribute this message. If you have received this communication in error, please notify Weaver immediately by e-mail and by telephone at (800) 332.7952 and delete the original message from your system. Unauthorized interception of this e-mail is a violation of Federal criminal law.

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/31/2017 5:13:17 PM
To: Jason Eberstein [jeberstein@namanow.org]
Subject: RE: great seeing you

Great to hear from you and great to see you as well. I thought that meeting went well. I'll be in touch.
Best,
Mandy

From: Jason Eberstein [mailto:jeberstein@namanow.org]
Sent: Monday, July 31, 2017 9:58 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: great seeing you

Hey when things slow down (if they ever do) ping me – would love to grab lunch or a beverage and catch up….

Hope all is well.

Jason

Jason S. Eberstein
Director, State and Federal Government Affairs
NAMA
Phone: 301.537.4114

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 8/14/2017 5:51:34 PM
To: Reed Clay [Reed.Clay@gov.texas.gov]
CC: Brown, Byron [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=9242d85c7df343d287659f840d730e65-Brown, Byro]
Subject: E-Connect on Coal Ash

Reed,
Per our earlier conversation, I'm connecting you with Byron Brown who is our coal ash lead and resident expert.

Byron,
Reed works in Gov. Abbot's Office and has been immensely helpful on some air-related state issues. He had some questions related to coal ash, which is why I'm connecting him to you.

I hope you both can find a time to chat.

Best,
Mandy

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/26/2017 5:03:03 PM
To: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
CC: Dimitri.Karakitsos@hklaw.com
Subject: 2:30

Dimitri, Email Alex when you get in the building. See you soon.

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/31/2017 9:52:56 PM
To: Surya Gunasekara [surya@sectionvii.com]
Subject: RE: Test

Success!!

-----Original Message-----
From: Surya Gunasekara [mailto:surya@sectionvii.com]
Sent: Monday, July 31, 2017 5:29 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Test

Surya G. Gunasekara
Principal
Section VII Strategies
202.288.8657

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/31/2017 9:52:05 PM
To: Smith, Shelia [ssmith@deltacouncil.org]
Subject: RE: Contact information

Yes **Personal Phone / Ex. 6**

From: Smith, Shelia [mailto:ssmith@deltacouncil.org]
Sent: Monday, July 31, 2017 5:47 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Contact information

Mandy,

Chip is wanting to contact you. Can you send me your contact information office and cell.

Thanks

Smith, Shelia
Delta Council Staff
ssmith@deltacouncil.org
662-686-3350

Appointment

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/17/2017 10:01:36 PM
To: Charles.Spell@aps.com

Subject: Meeting Forward Notification: Four Corners Federal Implementation Plan (FIP)

Start: 7/17/2017 10:30:00 PM
End: 7/17/2017 11:00:00 PM
Show Time As: Busy

Your meeting was forwarded

Gunasekara, Mandy has forwarded your meeting request to additional people.

Meeting

Four Corners Federal Implementation Plan (FIP)

Meeting Time

Friday, July 21, 2017 4:00 PM - Friday, July 21, 2017 5:00 PM

Recipients

Bolen, Brittany,Dravis, Samantha,Letendre, Daisy,Schwab, Justin

All times listed are in the following time zone: (UTC-05:00) Eastern Time (US & Canada)

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/31/2017 9:33:52 PM
To: reed.clay@gov.texas.gov
Subject: TX RH
Attachments: TX RH MOA_DRAFT.DOCX

Hi Reed,

Thank you for following up. Per our conversation, attached is the draft MOA that was sent by Region 6 to TCEQ last week. TCEQ gave us some initial feedback on formatting that has not been incorporated. Know this is simply a starting point. Let me know if you need additional information and I look forward to following up soon.

Best,
Mandy
202-564-2314 (desk)
202-306-8538 (cell)

Mandy M. Gunasekara
Senior Policy Advisor for Office of Air and Radiation
Office of the Administrator
US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/26/2017 2:01:22 AM
To: wilfried pengou fongang Personal Email / Ex. 6
CC: Personal Email / Ex. 6
Subject: Re: Hello

Hi Wilfried,

It was nice meeting you. I'm transferring this conversation to my gmail account, since it is not work related.

Tomorrow morning I'll connect you with a few folks involved in the program that will be better situated to discuss further. It sounds like you already looked into it, but just in case it is helpful, here is the link to the website:https://imagine1day.org/

Have a good night,
Mandy

Sent from my iPhone

On Jul 25, 2017, at 7:12 PM, wilfried pengou fongang Personal Email / Ex. 6 wrote:

> Hello Mandy,
> This is wilfried, the Uber driver. It was a pleasure
> chatting with you. I am looking forward to better know your organization. I'm starting the
> reading. Thank you for your time.

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/28/2017 10:22:43 AM
To: Stephanie Salmon **Personal Email / Ex. 6**
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: Re: Am Foundry Society - Meeting with Foundry Owners - MANY THANKS!

Thanks, Stephanie. It was great to see you and I enjoyed meeting some of the other members. I look forward to the follow up.
Best,
Mandy I

Sent from my iPhone

On Jun 27, 2017, at 8:41 PM, Stephanie Salmon <ssalmondc@gmail.com> wrote:

Mandy
Thank you so much for filling in for Samantha Dravis on short notice last week – I really appreciated that you took time from your busy schedule to speak to the members of the American Foundry Society at our breakfast event.
Your presentation helped to make this year's meeting a great success. We will be back in contact soon regarding some specific AFS air issues.
In the meantime, hope you can relax and spend time with your family over 4th of July.

Thanks again!
Regards,
Stephanie

Stephanie Salmon I Vice President Government Affairs I **American Foundry Society – Washington Office**
25 Massachusetts Ave, NW - Suite 800 I Washington, D.C. 20001
Ofc: 202-452-7135 - Cell: 571-242-0186 I ssalmon@afsinc.org
Metalcastings Make America Strong

On Jun 20, 2017, at 8:47 AM, Stephanie Salmon <ssalmondc@gmail.com> wrote:

Mandy
Samantha Greenwalt was supposed to speak to our group for breakfast tomorrow at 7:30 / 8:00 am on Wed and is now not available – is there any chance you could fill in?
We would be extremely grateful and appreciative.
Thanks
Stephanie

Stephanie Salmon I Vice President Government Affairs I **American Foundry Society – Washington Office**
25 Massachusetts Ave, NW - Suite 800 I Washington, D.C. 20001
Ofc: 202-452-7135 - Cell: 571-242-0186 I ssalmon@afsinc.org

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/18/2017 12:01:40 AM
To: Ray Bucheger [Ray@federalrelations.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Meeting Request to Discuss Jordan Cove LNG (per Mike Catanzaro)

Great – see you then.

From: Ray Bucheger [mailto:Ray@federalrelations.com]
Sent: Monday, July 17, 2017 8:00 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Meeting Request to Discuss Jordan Cove LNG (per Mike Catanzaro)

Hi Mandy:

1pm on Friday works for us. We appreciate your time.

Ray

On Jul 17, 2017, at 7:58 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hi Ray,
> Friday afternoon would work best – either 1 or 2 pm. Please let me know what you prefer. Alex (cc'd) can firm up the remaining logistics.
> Best,
> Mandy
>
> ---
>
> **From:** Ray Bucheger [mailto:Ray@federalrelations.com]
> **Sent:** Monday, July 17, 2017 5:14 PM
> **To:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> **Subject:** Re: Meeting Request to Discuss Jordan Cove LNG (per Mike Catanzaro)
>
> Hi Mandy:
>
> Following up on this – any chance you have some time to meet either Wednesday after 4:30 or Friday, either first thing in the morning, or mid-day?
>
> Thank you
>
> Ray
>
> ---
>
> **From:** Ray Bucheger <ray@federalrelations.com>
> **Date:** Thursday, July 13, 2017 at 8:46 PM
> **To:** Mandy Gunasekara <Gunasekara.mandy@epa.gov>
> **Subject:** Meeting Request to Discuss Jordan Cove LNG (per Mike Catanzaro)
>
> Hi Mandy:

Mike suggested I reach out to you. I represent Jordan Cove LNG, which is working to permit an LNG export facility in southwest Oregon. I have Jordan Cove's CEO, Betsy Spomer, in town next week, and I'm hoping you have some time for us to come in to discuss an issue we have run into.

There seems to be a question about whether LNG facilities are considered fuel conversion facilities under the Clean Air Act Prevention of Significant Deterioration (PSD) program. We don't believe LNG facilities should be classified as such, but there seem to be inconsistencies across regions, and we are concerned about what that could mean for the Jordan Cove permitting process.

Any chance you have some time to meet late in the afternoon on Wednesday (July 19) or on Friday morning (July 21)?

Thank you in advance for your time.

Ray

Ray Bucheger
Pioneer Group & FBB Federal Relations
Affiliated with Lindsay Hart, LLP
1120 G Street, NW Suite 1020
Washington, DC 20005
office: 202-783-3333
cell: 202-236-5101
ray@federalrelations.com

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/27/2017 3:41:50 PM
To: jimbruce@ups.com
Subject: RE: UPS announcements

Ok - great. Look forward to connecting.

-----Original Message-----
From: jimbruce@ups.com [mailto:jimbruce@ups.com]
Sent: Tuesday, June 27, 2017 11:40 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: UPS announcements

Mandy,

Here is our press release today about our new goals.

https://pressroom.ups.com/pressroom/ContentDetailsViewer.page?ConceptType=PressReleases&id=1498485329184-479

Will call you shortly,

Jim Bruce

-----Original Message-----
From: Gunasekara, Mandy [mailto:Gunasekara.Mandy@epa.gov]
Sent: Tuesday, June 27, 2017 11:22 AM
To: Bruce Jim (RKH5DRX) <jimbruce@ups.com>
Subject: [EXTERNAL] Re: UPS announcements

202-306-8538 is the best number. I'm free at 1145

Sent from my iPhone

> On Jun 27, 2017, at 10:55 AM, "jimbruce@ups.com" <jimbruce@ups.com> wrote:
>
> Mandy,
>
> Can I give you a call about announcements on new environmental goals we at UPS have today? I am following up on discussions you or Administrator Pruitt had with Penny Naas in Europe. I also spoke with someone from EPA when they presented at WRI.
> What number is best to call you and when?
> Thanks
> Jim Bruce
>
> Sent from my iPhone

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/12/2017 9:45:45 PM
To: Horner, Elizabeth (EPW) [Elizabeth_Horner@epw.senate.gov]
Subject: Re: Checking in

Yes- I'll reach out tomorrow!

Sent from my iPhone

On Jul 12, 2017, at 5:28 PM, Horner, Elizabeth (EPW) <Elizabeth_Horner@epw.senate.gov> wrote:

> Hi Mandy,
>
> Hope you're doing well! Let me know if you have time to chat some time in the next few days. My direct is below.
>
> Elizabeth
>
> Elizabeth L. Horner
> Majority Counsel
> Senate Committee on Environment and Public Works
> Elizabeth_Horner@epw.senate.gov
> (202) 224-7841

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/27/2017 10:21:11 PM
To: Chiang, Amy [Amy.Chiang@Honeywell.com]
Subject: RE: Catch up!

Are you free right now? Personal Phone / Ex. 6

From: Chiang, Amy [mailto:Amy.Chiang@Honeywell.com]
Sent: Tuesday, June 27, 2017 5:33 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Catch up!

Sorry I didn't get a hold of you earlier…let me know if you have time to catch up tonight and if you want to talk quickly about the meeting tomorrow.

Best,
Amy

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/27/2017 3:21:38 PM
To: jimbruce@ups.com
Subject: Re: UPS announcements

Personal Phone / Ex. 6 is the best number. I'm free at 1145

Sent from my iPhone

> On Jun 27, 2017, at 10:55 AM, "jimbruce@ups.com" <jimbruce@ups.com> wrote:
>
> Mandy,
>
> Can I give you a call about announcements on new environmental goals we at UPS have today? I am following up on discussions you or Administrator Pruitt had with Penny Naas in Europe. I also spoke with someone from EPA when they presented at WRI.
> What number is best to call you and when?
> Thanks
> Jim Bruce
>
> Sent from my iPhone

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/5/2017 8:02:33 PM
To: McGrath, William J. [wmcgrath@bhfs.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Meeting Request- WPX Energy

Hi Bill,

Thank you for reaching out. I'd be happy to meet and will also invite two of my colleagues – Brittany Bolen and Samantha Dravis. Alex, can you help facilitate the logistics?

Best,
Mandy

From: McGrath, William J. [mailto:wmcgrath@bhfs.com]
Sent: Wednesday, July 5, 2017 3:23 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Meeting Request- WPX Energy

Mandy,

Byron referred me over to you. I am writing to request a meeting on behalf of our client WPX energy on July 26th. They are in town the and are most concerned about the QuadOa regulations and how that affects their operations. Do you have any time available on the 26th? I would anticipate the meeting would only take 30 minutes and we are available anytime other than 1-2:30.

Thanks,
Bill

William J. McGrath
Brownstein Hyatt Farber Schreck, LLP
1155 F Street N.W., Suite 1200
Washington, DC 20004
202.383.4703 tel
wmcgrath@bhfs.com

STATEMENT OF CONFIDENTIALITY & DISCLAIMER: The information contained in this email message is attorney privileged and confidential, intended only for the use of the individual or entity named above. If the reader of this message is not the intended recipient, you are hereby notified that any dissemination, distribution or copy of this email is strictly prohibited. If you have received this email in error, please notify us immediately by calling (303)-223-1300 and delete the message. Thank you.

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/27/2017 2:06:28 PM
To: Marc Himmelstein [Marc_Himmelstein@nes-dc.com]
Subject: RE: Admin Pruitt Meeting

Ok - great. I'll give you a call after then.

-----Original Message-----
From: Marc Himmelstein [mailto:Marc_Himmelstein@nes-dc.com]
Sent: Tuesday, June 27, 2017 10:05 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: Admin Pruitt Meeting

I'm open much of the afternoon after 1:30 My office is Personal Phone / Ex. 6 Thx

Sent from my iPad

On Jun 27, 2017, at 10:00 AM, Gunasekara, Mandy
<Gunasekara.Mandy@epa.gov<mailto:Gunasekara.Mandy@epa.gov>> wrote:

Hi Marc,

I'm preparing all the materials for the Administrator's meeting with you tomorrow. Do have some time this afternoon to touch base on issues you plan to discuss? If so, what is the best number?

Best,
Mandy

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 7/13/2017 2:34:29 AM
To: Personal Email / Ex. 6
Subject: Fwd: Official Picture

Sent from my iPhone

Begin forwarded message:

From: "Vance, Eric" <Vance.Eric@epa.gov>
To: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Cc: "Dominguez, Alexander" <dominguez.alexander@epa.gov>, "Slotkin, Ron" <slotkin.ron@epa.gov>, "Rodgers, Ryan" <Rodgers.Ryan@epa.gov>
Subject: RE: Official Picture

Hi Mandy,
Here's your portrait in three sizes. 8x10 is for prints, 5x7 works well for publication and 2x3 should be reserved for web use.

Cheers,
e

Eric Vance
Chief Photographer, USEPA
Office of the Administrator
1200 Pennsylvania Ave, NW
Washington, DC 20640
WJC-North, Room 6330K

202.564.2655 office
202.689.9393 mobile

***
Link to Office of Multimedia photo galleries, accessible from within EPA's network.
http://intranet.epa.gov/media/
***

From: Gunasekara, Mandy
Sent: Thursday, July 06, 2017 7:54 AM
To: Vance, Eric <Vance.Eric@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: Official Picture

Ok- thank you for the heads up. Enjoy GA!

Sent from my iPhone

On Jul 6, 2017, at 7:37 AM, Vance, Eric <Vance.Eric@epa.gov> wrote:

> Hi Mandy,
> I got pulled away yesterday and didn't have time to work on your portrait. Now I'm heading to GA. I'll finish it for you Monday.
>
> Ryan, **Mandy M. Gunasekara**
> Senior Policy Advisor for Office of Air and Radiation
> Office of the Administrator
>
> Is ready to post. Thanks!
>
> Regards,
> E
>
> Eric Vance
>
> Chief Photographer, USEPA
> Office of the Administrator
> 1200 Pennsylvania Ave, NW
> Washington, DC 20640
> WJC-North, Room 6330K
>
> 202.564.2655 office
> 202.689.9393 mobile
>
> ***
> Link to Office of Multimedia photo galleries, accessible from within EPA's network.
> http://intranet.epa.gov/media/
> ***
>
> On Jul 3, 2017, at 2:53 PM, Dominguez, Alexander <dominguez.alexander@epa.gov> wrote:
>
>> Great thank you and done. Have a good 4th!
>>
>> ---
>>
>> **From:** Vance, Eric
>> **Sent:** Monday, July 3, 2017 2:51 PM
>> **To:** Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
>> **Cc:** Dominguez, Alexander <dominguez.alexander@epa.gov>
>> **Subject:** Re: Official Picture
>>
>> 9:00 is fine. Would you send a scheduler please? WJC North room 6330k
>>
>> Eric Vance

Chief Photographer, USEPA
Office of the Administrator
1200 Pennsylvania Ave, NW
Washington, DC 20640
WJC-North, Room 6330K

202.564.2655 office
202.689.9393 mobile

***
Link to Office of Multimedia photo galleries, accessible from within EPA's network.
http://intranet.epa.gov/media/
***

On Jun 30, 2017, at 9:20 AM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hi Eric,
>
> Can we set up a time for me to get my official picture done? I'm flexible later next week if you are going to be around. Please let me know.
>
> Best,
> Mandy
>
> **Mandy M. Gunasekara**
> Senior Policy Advisor for Office of Air and Radiation
> Office of the Administrator
> US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/30/2017 9:49:51 PM
To: Joseph Majkut [jmajkut@niskanencenter.org]
CC: Andrew Mills [amills@niskanencenter.org]
Subject: Re: EPA Climate Science Review

Hey Joseph,

Great to hear from you and I hope you are well. Thanks for the info- I'll pass it along and look forward to touching base soon.

Happy Fourth! us
Mandy

Mills- I hope you are well too!!

Sent from my iPhone

On Jun 30, 2017, at 2:09 PM, Joseph Majkut <jmajkut@niskanencenter.org> wrote:

> Mandy,
>
> It's been a while since we talked, but I hope you've landed well at EPA.
>
> After the E&E News reports about a possible climate science red team, I wanted to share this supportive blog post I wrote today.
>
> https://niskanencenter.org/blog/can-red-team-exercise-exorcise-climate-debate/
>
> Even climate hawks like us should support these efforts and I have been putting together some thoughts (beyond those in the post) for what a successful red team exercise might look like. If you are working on this issue, or know who is, I would be happy to share my thinking.
>
> All the best and happy fourth!
>
> Joseph
>
> --
> Joseph Majkut
> Director of Climate Science
> Niskanen Center
> 820 1st St. NE, Suite 675
> Washington DC, 20002
>
> jmajkut@niskanencenter.org
> https://niskanencenter.org/

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/30/2017 1:58:02 PM
To: Harding, Andrew (EPW) [Andrew_Harding@epw.senate.gov]; Brunner, Jan (EPW) [Jan_Brunner@epw.senate.gov]
Subject: RE: connecting you two

yes

From: Harding, Andrew (EPW) [mailto:Andrew_Harding@epw.senate.gov]
Sent: Friday, June 30, 2017 9:44 AM
To: Brunner, Jan (EPW) <Jan_Brunner@epw.senate.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: connecting you two

Mandy-mills wants your EPA email. May I forward it to him?

Sent from my iPhone

On Jun 30, 2017, at 9:43 AM, Brunner, Jan (EPW) <Jan_Brunner@epw.senate.gov> wrote:

Jan Brunner
Majority Counsel
Senate Committee on Environment and Public Works
415 Hart Senate Office Building
202-224-9705 (direct)

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/30/2017 8:04:44 PM
To: Patrick Wilson [patrick.wilson@cummins.com]
Subject: RE: VW Settlement Question

Glad he was helpful.

Great to hear on the DERA reauth.

Happy Fourth!

From: Patrick Wilson [mailto:patrick.wilson@cummins.com]
Sent: Friday, June 30, 2017 3:23 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Re: VW Settlement Question

Thanks Mandy. I spoke to Phil yesterday and he was able to answer all of my questions!! You're a star!

Also, did you see that Rep. Ted Poe introduced the DERA re authorization bill yesterday? Just wanted to flag that for you guys.

Have a wonderful Independence Day!

Thanks again!

Patrick

_____
W. Patrick Wilson
Cummins Inc.
202-997-3597 (m)
Sent from my iPhone 7s

On Jun 30, 2017, at 3:05 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:

> Hi Patrick,
>
> Just to close the loop from my end – Phil Brooks should have reached out to you to answer any of your questions. Did that occur? Please let me know if you need any additional help.
>
> Best,
> Mandy
>
> **Mandy M. Gunasekara**
> Senior Policy Advisor for Office of Air and Radiation
> Office of the Administrator
> US Environmental Protection Agency

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/21/2017 1:24:20 PM
To: Ghanta, Venu G [Venu.Ghanta@duke-energy.com]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: your voicemail

Hi Venu,
Since I keep missing you (and frankly I'm embarrassed that we've yet to actually connect) I've cc'd Alex who can formally set up a time to either sit down in person or touch base on the phone. I have some time this Friday if that would work for you.
Best,
Mandy

From: Ghanta, Venu G [mailto:Venu.Ghanta@duke-energy.com]
Sent: Saturday, May 27, 2017 9:35 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: your voicemail

Hi Mandy-

Sorry I missed your call Friday. What would be a good time to talk next week? In particular, I want to make sure we touch base on CSAPR.

Hope you are well and get some time off over the weekend.

Regards, Venu

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/21/2017 5:03:08 PM
To: Personal Email / Ex. 6
Subject: RE: At North Lobby

Alex is on his way down to get you

-----Original Message----- Personal Email / Ex. 6
From: Joseph Mendelson III [redacted]
Sent: Wednesday, June 21, 2017 1:01 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: At North Lobby

Hi Mandy,

I'm in the North lobby. The security desk just tried the escort number but no answer.

Thanks,
Joe

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/19/2017 4:24:29 PM
To: Rachel Jones [RJones@nam.org]
CC: Dominguez, Alexander [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=5ced433b4ef54171864ed98a36cb7a5f-Dominguez,]
Subject: RE: Meeting request

I'm cc'ing Alex who can help set this meeting up. Sorry for delayed response!
Since we are talking about the reg priorities, have you talked to Brittany and Sam? Do you want to include them in on this meeting as well?

From: Rachel Jones [mailto:RJones@nam.org]
Sent: Tuesday, June 13, 2017 11:43 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: Meeting request

Mandy--

I hope you saw our submission on reg priorities. Would you have time to sit down with us and a few others to discuss?

Thanks for your consideration.

Rachel Jones
Direct 202-637-3175
Cell 804-380-6542

Message

From: Gunasekara, Mandy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=53D1A3CAA8BB4EBAB8A2D28CA59B6F45-GUNASEKARA,]
Sent: 6/15/2017 7:46:33 PM
To: Personal Email / Ex. 6
Subject: E-Connect

Hi Randy,

It was nice to meet you over the phone. You now have my email address as well. I look forward to staying in touch and working with you on ways to build confidence in the eyes of the American people on this important issue.

Don't hesitate to reach out with any questions or suggestions.

Best,
Mandy