To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: ECOS
Sent: Fri 12/22/2017 4:34:41 PM
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Subject: ECOS Leaders Meet in Washington to Advance Cooperative Federalism, Congress Funds Government thru Mid-January, & More
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ECOSWIRE

Friday, December 22, 2017

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ECOS will not be published on December 29 and will resume publication January 5. From all the ECOS staff, best wishes for the holidays and New Year!

ECOS Leaders Advance Discussions with U.S. EPA on Cooperative Federalism and More

This week ECOS President Todd Parfitt of Wyoming, Vice President Becky Keogh of Arkansas, Secretary-Treasurer Jim Macy of Nebraska, and ERIS President David Paylor of Virginia conducted visits with U.S. EPA officials in Washington, DC, to continue conversations around oversight of delegated programs and advancing Cooperative Federalism 2.0. The ECOS leaders met with Henry Darwin, Deputy Assistant Administrator and Chief of Operations, and officials in the U.S. EPA Offices of Air and Radiation and Enforcement and Compliance Assurance.

The leadership also spent time on the search process for a new ECOS/ERIS Executive Director. The members' commitment to the organizations agendas at this busy time of year is sincerely appreciated. [Dunn]

From left to right: Todd Parfitt (WY), Becky Keogh (AR), Susan Bodine (U.S. EPA OECA), David Paylor (VA), and Jim Macy (NE).

Congress Funds Government through Mid-January

On December 20, Congress passed a Continuing Resolution (CR) to fund the federal government through January 19, 2018. The third CR in the FY 2018 budget cycle, this bill maintains FY17 spending levels, albeit with some budget anomalies associated with various policy riders. The bill is expected to be signed by President Trump before the current CR expires at midnight Friday.

With lawmakers imminently heading home for the holiday recess, negotiations will resume in January on overall spending caps as well as several unrelated issues expected to be rolled into the budget debate. [McAleer]

U.S. EPA Announces Next Steps Following Proposed CPP Repeal

U.S. EPA on December 18 issued an Advance Notice of Proposed Rulemaking (ANPRM) indicating that the agency will solicit public input as it considers the next regulatory steps to limit greenhouse gas emissions from existing electric utility generating units (EGUs), also known as power plants.

The ANPRM is a separate, but related, action to the October 16 proposal to repeal the Clean Power Plan. It offers the public the opportunity to comment on specific topics for the agency to consider in developing any subsequent proposed rule. EPA is specifically soliciting information on systems of emission reduction for EGU facilities, compliance measures, and state planning requirements under Clean Air Act section 111(d).

EPA will take comment on the ANPRM for 60 days following publication in the *Federal Register*. More information, including the ANPRM and fact sheet, are available here. [Poole]

ECOS and Other State Media Associations Co-Sign Letter on VIDA

ECOS and three other nonprofit associations representing state environmental regulatory agencies (the Association of Clean

Water Administrators [ACWA], the Association of State Wetland Managers [ASWM], and and the Association of Fish and Wildlife Agencies [AFWA]) co-signed a letter to members of Congress this week detailing the potential consequences for environmental quality if the Vessel Incidental Discharge Act (S. 1129) were enacted. The associations previously wrote a letter of concern on VIDA in June 2016.

Read this week's letter here. [Longsworth]

U.S. EPA Finalizes e-Manifest User Fee Rule

U.S. EPA on December 20 finalized its rule for setting and revising fees for users of the e-Manifest system. This final e-Manifest User Fee Rule completes the regulatory framework for implementing Congress' *Hazardous Waste Electronic Manifest Establishment Act of 2012*, which authorizes EPA to implement a national system and collect user fees to recover the costs of developing and operating the system.

Click here for more information about the final e-Manifest User Fee Rule, including the pre-publication version.

For additional information, join EPA for the next e-Manifest webinar on **January 3 at 2-3:30 p.m. Eastern** by accessing the live webinar here. [Parisien]

Former U.S. EPA Acting Administrator McCabe Tapped to Head New Jersey DEP

New Jersey Governor-Elect Phil Murphy on December 20 announced his selection of former U.S. EPA Acting Administrator Catherine McCabe to serve as Commissioner of the state Department of Environmental Protection. She will succeed Bob Martin in the post.

Among McCabe's previous positions are Deputy Regional Administrator of EPA's Region 2 and Deputy Chief of the U.S. Department of Justice Environmental Enforcement Section. ECOS looks forward to welcoming her as a member! [Parisien]

Ehm Selected as Executive Committee Region 7 Representative

ECOS is pleased to announce that Bill Ehm of Iowa has been selected by his regional colleagues to serve as Region 7 Representative to the Executive Committee. Ehm fills the unexpired term of Jim Macy, who was elected Secretary-Treasurer earlier this year.

Ehm's term is effective through the 2018 Fall Meeting, with the option for renewal for a full two-year term. [Swanson]

Bill Ehm of Iowa

Cross Off Spring Meeting Registration and Reservations from Your Holiday To Do List

ECOS' elves are already hard at work planning a timely and wide-ranging Spring Meeting on *Getting to Results*. The gathering, to be held March 20-22 ECOS Spring Meeting in St. Paul, Minnesota, will spotlight ECOS' expanding Results.org effort, as well as state initiatives to accelerate and enhance land cleanups, promote cross-agency partnerships, ensure a secure and sustainable energy future, encourage Sustainable Materials Management, achieve tangible results through Cooperative Federalism 2.0 and E-Enterprise, tackle PFAS, and effectively communicate progress to the public.

Also planned are keynotes by Governor Mark Dayton of Minnesota (invited) and a generational expert on building for future agency success, a point-counterpoint session on Clean Water Action 404 assumption, and two offsite evening events including an excursion to the Science Museum of Minnesota.

Register by **February 16** to receive the reduced early bird rate. Also, act now to reserve a room at the hotel by calling The Saint Paul Hotel at (800) 292-9292, and mention the ECOS Spring Meeting to receive the group rate. The special ECOS group rates of $149 (government and staff room) and $169 (deluxe room) plus tax are available until February 19 or sellout of the room block, whichever is sooner. ECOS room nights include March 19, 20, and 21, with limited availability March 22. Visit the Spring Meeting page for additional details.

For agenda or sponsorship information, please contact Lia Parisien of ECOS. Contact Sarah Grace Longsworth for registration information and Megan Swanson for hotel information. [Parisien]

State News You Can Use

New Mexico Develops Streamlined Oil and Gas Air Emissions Application

Ohio EPA Announces 2018 Water Pollution Control Loan Fund Program Management Plan

Mississippi Offers Tips to Promote a Green Holiday Season

Need-to-Know News in Compliance and Enforcement, Air, & Water

U.S. EPA Delays FY17 Data Verification, Plans Webinar on Verification Tool and Improvements

Area of Focus: *Compliance and Enforcement*

This week, ECOS shared with members a letter from U.S. EPA's Office of Enforcement and Compliance Assurance (OECA) announcing a delay in the timing of the FY2017 data verification period to allow states time to review changes to the metrics and measures for the State Review Framework Round 4.

The letter also announces a national webinar on **January 16, 2018 at 3-4:15 p.m. Eastern** regarding data verification and improvements EPA has made to its tool that states use to complete their verification process. States may register here.

For more information, contact Rebecca Kane of OECA. [Graves]

Court Orders U.S. EPA to Set Timetable for Ozone Designations

Area of Focus: *Air*

On December 20, the U.S. Court of Appeals for the DC Circuit ordered U.S. EPA to act by **January 12** to set a firm date and outline a compliance timetable for remaining attainment designations for the 2015 ground-level ozone standard.

All designations were due October 1. U.S. EPA formally published designations for areas of the country in attainment on November 16. The final decisions for areas likely out of compliance have not been released.

In June 2017, EPA Administrator Scott Pruitt announced a one-year extension that would have pushed back the deadline for all attainment designations until October 2018. This extension was withdrawn in August 2017. For enforcement purposes, the attainment designations start the clock for states that must draft cleanup plans for areas that are out of compliance. [Poole]

U.S. EPA Launches Water System Partnerships Website

Area of Focus: *Water*

U.S. EPA has launched a new interactive website to promote awareness of the benefits of drinking water partnerships. For communities and utilities facing growing costs and challenges for treating drinking water, drinking water system partnerships provide opportunities to increase capacity, share costs, and leverage other resources.

The new website highlights ways partnerships can address these challenges, enhancing public health by working together and sharing information through a user-friendly interface accessible to states, communities, utilities, and others. [Piper]

U.S. EPA Appointments

Stepp Moving From Region 5 to Helm of Region 7

U.S. EPA Administrator Scott Pruitt on December 19 announced the appointment of former ECOS member Cathy Stepp to become Regional Administrator for Region 5.

Stepp currently serves as Principal Deputy Regional Administrator for Region 7 and will return to the Midwest region, where

was Secretary of the Wisconsin Department of Natural Resources from 2011 to 2017. Stepp also previously served as a Wisconsin State Senator. [Parisien]

ECOS Staff News

Graves Promoted to Executive Project Manager

ECOS congratulates Beth Graves on her recent promotion to the position of Executive Project Manager!

Graves, who has worked for the association for a decade, spearheads work conducted under the E-Enterprise for the Environment initiative and the ECOS Planning Committee. [Parisien]

Opportunities

Reminder: State Communications Leads Sought for New ECOS Community of Practice

ECOS invites all members to provide the contact information for their agency's lead communications expert to become part of our new Communications Community of Practice. In accordance with ECOS President Todd Parfitt's 2017-2018 priorities, ECOS is launching this virtual learning community for state communications professionals to share best practices, success stories, challenges, and transferable lessons.

It is anticipated that once all contacts are identified, the group may hold three calls per year and also use one another as resources to share questions and information. The group also will periodically interface with U.S. EPA communications leads from Headquarters and the Regions.

Contact information for your state expert may be sent to Nia Duke of ECOS. [Duke]

U.S. EPA Invites Nominations to National Advisory Council for Environmental Policy and Technology

U.S. EPA is seeking nominees to fill several potential vacancies on the National Advisory Council for Environmental Policy and Technology (NACEPT). Representatives of state, local, and tribal governments, academia, industry, and nongovernmental organizations serve on this federal advisory committee.

NACEPT provides advice to the EPA Administrator on a range of policy, management, and technology issues.

For more information, including how to apply, refer to the *Federal Register* notice. The deadline for applications is **January 3, 2018**. [Hanson]

U.S. EPA Seeks Nominations to Commission for Environmental Cooperation

Committee

U.S. EPA invites nominations for appointment to the Governmental Advisory Committee to advise the U.S. Representative to the Commission for Environmental Cooperation.

Nominees are sought by **February 16, 2018** from the state, local, and tribal government sectors. For more information, click here. [Parisien]

Upcoming Events

Webinars

ITRC on Remedy Selection for Contaminated Sediments

The Interstate Technology & Regulatory Council (ITRC) will hold its first online training of 2018 on *Remedy Selection for Contaminated Sediments* on **January 9, 2018 at 1-3:15 p.m. Eastern.**

The sediments underlying many of our nation's major waterways are contaminated with toxic pollutants from past industrial activities. Cleaning up contaminated sediments is expensive and technically challenging. Sediment sites are unique and complex, and require a multidisciplinary approach and often project managers lack sediments experience. This training course will teach participants to apply the associated ITRC technical and regulatory guidance as a tool to overcome the remedial challenges posed by contaminated sediment sites.

Learn more and register here. [Bodi]

Exchange Network on Grant Applications

In support of the FY 2018 Exchange Network (EN) Grant cycle, U.S. EPA is hosting webinars to assist interested applicants. The final webinar will be held **January 10, 2018 at 1-2 p.m. Eastern**. Topics will include a summary of the FY 2018 EN Grant program, new and modified solicitation notice content, administrative procedures for submitting applications, tips on writing a high-quality application, and a question-and-answer session for potential applicants.

To participate, call (866) 299-3188 and use conference code 2025660466#, and access this webinar link. An Adobe Connect account is not required to enter the webinar, and participants can simply log in as a guest.

For more information, please contact EPA's Salena Reynolds. [McAleer]

ECOS and U.S. EPA on ECHO

An E-Enterprise ECHO team led by Oklahoma and EPA has identified potential improvements to the display, usability, and accuracy of U.S. EPA's Enforcement and Compliance History Online (ECHO) website. The team has identified a number of possible enhancements to improve the user experience and the display of facility compliance history.

Two identical webinars were planned to share the proposed changes with the co-regulator community and receive

feedback. The first was held on December 12, and a second webinar will repeat the same content on **January 11, 2018 at 12-2 p.m. Eastern**. Please register here.

In advance of the webinars, states can learn more about the proposed changes in this summary document. Please note that the changes are proposals only at this point and the team is seeking comments and input to ensure that proposed changes will meet the needs of ECHO stakeholders. You may send general written comments, questions, and markup of the summary document to Layne Piper of ECOS.

Oklahoma, as state team lead, asks states to provide input on a very brief set of questions to help the team better understand the ECHO community's preferences for a specific set of display and labeling options. Please click here by **January 26** to participate. [Piper]

NEWMOA and NERC on C&D Materials Management & Markets in the Northeast

The Northeast Waste Management Officials Association (NEWMOA) and Northeast Recycling Council (NERC) will host a webinar on Construction & Demolition (C&D) Materials Management and Markets in the Northeast on **January 17, 2018 at 2-3:30 p.m. Eastern**.

The discussion will center on two main areas:

- The results of NEWMOA's recently released analysis of data collected by the environmental agencies in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont on architectural C&D materials disposal, processing, and recovery for reuse and recycling.
- The results of a Massachusetts Department of Environmental Protection (MassDEP) funded study that evaluated the current and future status of C&D debris management in Massachusetts, and identified and recommended potential opportunities for the diversion of a greater proportion of recyclable materials to recycling markets. NERC administered and contracted with DSM Environmental Services to conduct the project. MassDEP has established a goal of diverting 50 percent of C&D materials from disposal, but in recent years the actual diversion rate has plateaued at around 30 percent. The primary objective of the analysis undertaken by DSM was to first assess incoming and outgoing materials at Massachusetts C&D processors and handling facilities, and to determine what the opportunities and constraints are to increase materials diversion beyond 30 percent.

Register for the webinar here. Please reach out to Connor MacCartney with any questions.
[MacCartney]

U.S. EPA on Urban Soil Contamination

U.S. EPA will hold its first Tools and Resources webinar of the New Year on **January 17, 2018 at 3-4 p.m. Eastern**. The webinar will focus on identifying sources (site-related or natural, anthropogenic) of soil contamination in urban settings, a process vital to decision-making during environmental cleanups.

Presenters will discuss EPA's methodology for citywide or urban area background data set collection, as well as results of a recent U.S. EPA study on soil contamination in Louisville and Lexington, Kentucky; Memphis and Chattanooga, Tennessee;

Raleigh and Winston-Salem, North Carolina; and Gainesville, Florida.

To register, click here. [Longsworth]

ECOS on 2018 Clean Water SRF

On **January 30, 2018 at 2-3:30 p.m. Eastern**, ECOS will host a webinar to highlight three states' innovative uses of Clean Water State Revolving Funds (CWSRF). The three featured projects demonstrate unique uses and dispersion of CWSRF funds, and offer valuable case studies that will build state capacity and knowledge.

See this flyer for more information on the presentations from Idaho, Iowa, and Massachusetts. The webinar is the product of a research project to document the flexibilities of the CWSRF. ECOS is working under a cooperative agreement with U.S. EPA's Office of Water.

Register here for the webinar, or contact Layne Piper for more information. [Piper]

To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: ECOS
Sent: Fri 8/4/2017 7:16:46 PM
Importance: Normal
Subject: ECOS Explores Lean, Superfund, & Results, Publishes Green Report on Permit Streamlining
Received: Fri 8/4/2017 7:17:59 PM

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ECOSWIRE

Friday, August 4, 2017

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States, U.S. EPA Gather in Denver to Talk Lean

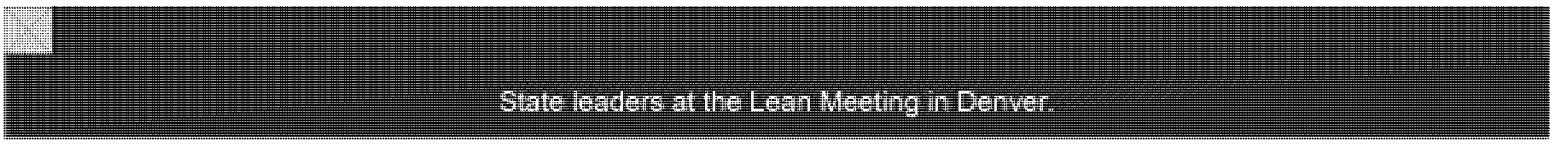
A group of 42 business process improvement (BPI) leaders representing 16 states and U.S. EPA met this week at EPA's Region 8 offices in Denver to share lessons learned and strengthen ties among environmental agency process improvement professionals. Over the course of the August 1-2 gathering, the group formulated a plan to coordinate their respective initiatives, share results data, and establish a structure for an official national BPI network.

State leaders and EPA Lean Advocates also gained insight from presentations and tours from several Colorado-based innovators including the City of Denver Peak Academy, Colorado Department of Transportation, and Governor's Office Lean

team.

ECOS thanks all the states that participated in the meeting: Arizona, Arkansas, California, Colorado, Delaware, Iowa, Minnesota, Montana, New Hampshire, Ohio, Rhode Island, Utah, Vermont, Washington, Wisconsin, and Wyoming. Please contact Owen McAleer of ECOS for more information on this work.

In related news, the EPA Office of the Inspector General (OIG) this week released a report finding that the agency "needs to institutionalize its 'Lean' program to reap cost and time benefits." Among OIG's recommendations to the agency was the "development of a cohesive strategy for leading, implementing, and monitoring the Lean initiative." Last month, EPA named former ECOS member Henry Darwin of Arizona as Assistant Deputy Administrator and Chief Operating Officer with the charge of implementing a Lean management system to achieve better results for the agency. Darwin will participate in an ECOS Fall Meeting roundtable on *Inspiring Innovation and a Change-Oriented Culture* alongside his Arizona successor, Misael Cabrera, and other states. [McAleer]



State leaders at the Lean Meeting in Denver.

ECOS Superfund Workgroup Holds Inaugural Call, Seeks More Members

Senate Hearing Focuses on Superfund Modernization

A new ECOS Superfund Workgroup on July 31 held its inaugural call to chart a cooperative federalism course in implementing the recent recommendations of the U.S. EPA Superfund Task Force recommendations (see July 28 edition of *ECOSWIRE*). Led by ECOS Waste Committee Chair Scott Thompson of Oklahoma, the workgroup will hold monthly calls to maximize state-federal cooperation in implementing the federal recommendations. Task force Chair Kell Kelly, Senior Advisor to the EPA Administrator, will participate in the workgroup along with other EPA officials and leaders of the Association of Solid Waste Management Officials (ASTSWMO).

On the call, ECOS members expressed support for the overarching goals of the recommendations to accelerate and improve cleanups and said states want to be an integral part of achieving them. Members pointed to a need to be involved upfront in issues like remedy selection and to find ways to avoid duplication of effort and contain costs to states.

In August 1 testimony before a Senate Environment & Public Works subcommittee, former ASTSWMO President Jeffery Steers echoed these sentiments, pointing to an opportunity to modernize certain aspects of Superfund law to acknowledge the role of states as co-regulators who operate sophisticated programs across the country. "Our members, and to some extent our regulated community, continue to be challenged with the skyrocketing financial obligations associated with remediating contaminated lands," Steers said.

Steers also pointed to ECOS' *Cooperative Federalism 2.0* effort during the question-and-answer period. C-SPAN's video coverage of the hearing is available here.

If you are interested in participating in the new ECOS workgroup, or have written comments or suggested call topics to

share, please contact Lia Parisien of ECOS. [Parisien/Harrison]

ECOS All-Member Webinar Provides Sneak Preview of ECOSResults.org

ECOS convened an All-Member Webinar on August 1 to provide an update on the ECOS Results Project and a first glimpse at preliminary infographics and site designs of ECOSResults.org. An adaptable and engaging website, ECOSResults.org will use charts, graphs, and other data displays to show the progress states are making to protect human health and the environment.

Under the leadership of ECOS President John Linc Stine of Minnesota and Past President Martha Rudolph of Colorado, ECOS launched the project in 2016 to identify common environmental, economic, and public health progress measures for all states to use. Fourteen common measures were selected in early 2017 following a robust state-led process through the ECOS Planning Committee, in coordination with the state environmental media associations.

ECOS members on the call were supportive of the design preview. Stay tuned for a demo of ECOSResults.org at the ECOS Fall Meeting. If you have any questions about the project, please contact Sonia Altieri or Connor MacCartney of ECOS. [Altieri]

New ECOS *Green Report* Spotlights State Permit Streamlining

In an effort to showcase state innovations in permitting processes, ECOS has prepared a *Green Report* on permit streamlining efforts.

The report, titled *Streamlining Permitting: An Inventory of State Environmental Agency Online Tools and Resources*, provides details of initiatives as they appear on the websites of state environmental agencies. [Harrison]

ECOS, Other Associations Urge U.S. EPA to Clarify 404 Assumption

This week ECOS and the Association of Clean Water Administrators and Association of State Wetland Managers sent a letter to U.S. EPA's Office of Water encouraging the agency to adopt the majority recommendations included in the final report of the Assumable Waters Subcommittee and undertake an effort to clarify Section 404(g), either through guidance or rulemaking.

The letter expresses appreciation for the agency's response to state requests to clarify the 404 assumption process, and says "many states already play a major role in implementation of dredge and fill regulations, and that combined state-federal programs provide effective, efficient, resilient, protective, and stable regulation in accordance with Section 404 of the Clean Water Act." [Piper]

ECOS Fall Meeting Early Registration Ends Today; Room

Block Closes August 9

Early registration closes today for ECOS' action-packed 2017 Fall Meeting in Jackson Hole, Wyoming on *Bright Ideas: States Leading the Way*. The interactive program ties together a number of cutting-edge ECOS initiatives of interest to a variety of stakeholders. Among the highlights, ECOS will feature outstanding programs selected for 2017 State Program Innovation Awards, unveil a new dashboard that states can use to better protect human health and the environment, and explore early wins in its Cooperative Federalism 2.0 campaign to forge an improved state-U.S. EPA partnership.

Confirmed keynoters are Wyoming Governor Matt Mead and former ECOS member Collin O'Mara (Delaware), now President & CEO of the National Wildlife Federation. Attendees also will be welcomed to the meeting by David Vela, Superintendent of Grand Teton National Park. U.S. EPA officials already confirmed to attend are Assistant Deputy Administrator & Chief of Operations Henry Darwin, Senior Advisor to the Administrator for Regional & State Affairs Ken Wagner, and Acting Deputy Administrator Mike Flynn. Sure to be a highlight of the meeting is an evening excursion to Grand Teton National Park.

The public portion of the Fall Meeting runs September 11 and 12, with **states-only sessions planned until 11:15 a.m. on September 13**. These discussions will be followed by the E-Enterprise for the Environmental Leadership Council Meeting on the afternoon of September 13 and morning of September 14 until 11:30 a.m. The special ECOS group rates at Snow King Resort are available until **August 9** or sellout of the room block, whichever is sooner.

See the Fall Meeting website for the agenda, online registration, hotel reservation link, hotel overflow suggestions, ground transportation options, and area attractions. For more information about the agenda, sponsorship opportunities, or the hotel, contact Lia Parisien of ECOS. For additional registration information, contact Sarah Grace Longsworth of ECOS. [Parisien]

State News You Can Use

New York YouTube Series Features DEC Staff and Their Work

Pennsylvania Develops App for O&G Inspections, Nominated for National Award

Tennessee Digitizes Septic System Cords for Public

Missouri Offers Compliance Assistance Visits

Rhode Island Offers $4 Million to Help Communities Protect Open Space

Utah Voluntary Cleanup Program Promotes Streamlined Process

Member Spotlight

Two Minutes with Julie Moore, Secretary, Vermont Agency of Natural Resources

How long have you been Secretary of the Vermont Agency of Natural Resources? What's your best experience thus far?

I was appointed by Governor Phil Scott in January 2017. My best experience thus far been the opportunity to learn from the amazing scientists and practitioners who work on the incredible diversity of issues ANR is tasked with – everything from cumulative contaminant risk to groundwater as a public trust to forest fragmentation and even endangered mussels!

How has being a member of ECOS benefited you?

ECOS provides the opportunity to meet my counterparts in other states. Still feeling quite new to the job, there is so much value in having a network of peers who are very generous with their time and sharing their experience.

What is the best management advice you've received?

"Play it straight." Ultimately, people – whether staff, advocates, or the public – appreciate direct, concise, honest answers, including saying "I don't know" when you don't know.

CONTINUED HERE

Need-to-Know News in Air & Waste

U.S. EPA Withdraws Extension for 2015 Ozone NAAQS Designations

Area of Focus: *Air*

On August 2, U.S. EPA withdrew the 1-year extension of the deadline for promulgating initial area designations for the 2015 Ozone National Ambient Air Quality Standards (NAAQS) published in the June 28 *Federal Register*. Through discussions with states concerning designations, EPA now understands that the information gaps that formed the basis of the extension may not be as expansive as the agency previously believed. There may be areas where designations could move forward in the next few months. Publication of this action in the *Federal Register* is expected within the next couple of weeks.

The action comes a day after several states filed a petition for review in the U.S. Court of Appeals for the DC Circuit. New York, California, Connecticut, the District of Columbia, Delaware, Illinois, Iowa, Maine, Maine, Massachusetts, Minnesota, New Mexico, Oregon, Rhode Island, Pennsylvania, Vermont, and Washington are asking the U.S. Court of Appeals to review EPA's decision to extend the deadline for promulgating initial area designations for the 2015 ozone NAAQS.

While not referencing the lawsuit directly, EPA Administrator Scott Pruitt notes in an August 2 press release, "Under previous Administrations, EPA would often fail to meet designation deadlines, and then wait to be sued by activist groups and others, agreeing in a settlement to set schedules for designation. We do not believe in regulation through litigation, and we take deadlines seriously." He adds, "We believe in dialogue with, and being responsive to, our state partners. Today's action

reinforces our commitment to working with the states through the complex designation process." [Poole]

U.S. EPA 2017 Air Trends Report Shows Significant Progress

Area of Focus: *Air*

On August 2, U.S. EPA released its annual air trends report titled *Our Nation's Air: Status and Trends Through 2016* that shows significant air quality strides during a time of economic growth.

Reporting that that this progress often is overlooked, EPA points to the Association of Air Pollution Control Administrators' report *The Greatest Story Seldom Told*, which explains that "[t]hrough the Clean Air Act's framework of cooperative federalism, hard-working state and local air agencies have been responsible for tremendous progress in virtually every measure of air quality."

The report shows that between 1990 and 2016, national concentration averages of harmful air pollutants decreased considerably, with:

- Lead (3-month average) down 99 percent;
- Carbon monoxide (8-hour) down 77 percent;
- Sulfur dioxide (1-hour) down 85 percent;
- Nitrogen dioxide (annual) down 56 percent;
- Ground-level ozone (8-hour) down 22 percent;
- Coarse Particulate Matter (24-hour) down 39 percent; and
- Fine Particulate Matter (24-hour) down 44 percent.

However, EPA Administrator Scott Pruitt does note, "Despite this success, there is more work to be done. Nearly 40 percent of Americans are still living in areas classified as 'nonattainment' for failing to achieve national standards. EPA will continue to work with states, tribes, and local air agencies to help more areas of the country come into compliance."

See more information here. [Poole]

U.S. EPA Tests New Smoke Sense App to Educate Public and Gather Information

Area of Focus: *Air*

U.S. EPA has released a new smartphone app that will help develop risk communication strategies and determine the extent that exposure to wildland fire smoke affects health and productivity. The Smoke Sense app, currently available only for Android phones, allows individuals to learn about wildfires and smoke health risks in their area, report their health symptoms, and report the range of actions they are willing to take to reduce their exposure. The app provides users current and forecasted air quality by zip code and a map showing current fires and smoke plumes. More information about the app and the research it supports is available here.

With the nation in the midst of wildfire season and wildfire smoke triggering air pollution advisories, states may want to review information in *Wildfire Smoke: A Guide for Public Health Officials* to help prepare for and address wildfire smoke events. [Hanson]

U.S. EPA Adds Superfund Sites to National Priorities List

Area of Focus: *Waste*

U.S. EPA announced July 31 that it is adding seven, and proposing to add four, hazardous waste sites to the Superfund program's National Priorities List (NPL). Superfund law directs EPA to update the NPL annually, and only sites added to the NPL are eligible to receive federal funding for long-term permanent cleanup.

"My goal as Administrator is to restore the Superfund program to its rightful place at the center of the agency's core mission," said EPA Administrator Scott Pruitt. "When we clean up these sites, we make communities healthier places to live and clear the way for development and increased economic activity."

The following sites are being added to the final NPL:

- The Battery Recycling Company in Bo. Cambalache, Puerto Rico
- Former Custom Cleaners in Memphis, Tennessee
- Highway 18 Ground Water in Kermit, Texas
- Microfab Inc. in Amesbury, Massachusetts
- Old Highway 275 and N. 288th Street in Valley, Nebraska
- Post and Lumber Preserving Co. Inc. in Quincy, Florida
- Saint-Gobain Performance Plastics in Village of Hoosick Falls, New York

The following sites are being proposed for addition to the NPL:

- Newark South Ground Water Plume in Newark, Delaware
- American Creosote DeRidder in DeRidder, Louisiana
- Mississippi Phosphate Corporation in Pascagoula, Mississippi
- Eagle Industries in Oklahoma City, Oklahoma

Federal Register notices and supporting documents for the final and proposed sites are here. [Parisien]

Opportunities

U.S. EPA Seeks State Officials for Local Government/Small Community Advisory Committees

U.S. EPA seeks local, state, and tribal elected and appointed officials for its Local Government Advisory Committee (LGAC) and the Small Community Advisory Committee (SCAC). The LGAC provides advice on the development and implementation of agency programs at the local level, while SCAC members serve to represent communities of under 10,000. Applications are due **August 10** for consideration for September 2017 appointments to 1-2 year terms.

The full solicitation is available here. [Parisien]

Upcoming Events

Calls

PFAS Workgroup

ECOS and U.S. EPA's joint PFAS Workgroup will host a bimonthly call for interested state and EPA partners on **August 7 at 4-5 p.m. Eastern**. The purpose of the call is to share information on PFAS work, including analytical methods, toxicity, and treatment. Monday's call will feature a discussion of EPA's cross-agency coordination of PFAS activities from the agency's Office of Research and Development (ORD) Acting Assistant Administrator Bob Kavlock, as well as an update on the EPA's PFAS Analytical Methods Workgroup from Co-Chairs Cindy Caporale of Region 3, Schatzi Fitz-James of the Office of Land and Emergency Management, and Chris Impellitteri of ORD. States will also have time to share and discuss their PFAS updates.

Please pre-register for the call by contacting Sarah Grace Longsworth of ECOS with questions or for a copy of the workgroup's May call summary. [Longsworth]

Webinars

ECOS and U.S. EPA on Compliance Research Part 2

Jodi Short of the University of California Hastings College of Law will present "Monitoring: A Review of Research on Inspection and Compliance for Regulators" on **August 9 at 3-4:30 p.m. Eastern**. The research highlights what is known about the way monitoring practices can drive – or undermine – compliance.

The Compliance Research Webinar Series, hosted by EPA OECA's NETI and designed for ECOS, U.S. EPA, and state environmental agencies, will help program administrators understand how collaboration with academics can identify effective and measureable approaches to compliance. In each of the webinars, social and behavioral scientists from top universities will present research findings on compliance monitoring, rule and permit design, reporting and transparency, and innovative enforcement. Following the presentations, participants will discuss program initiatives that can be put to the test through collaboration with academics.

Additional webinars will be held as follows:

- Rule and Permit Design – **September 28, 2-3:30 p.m. Eastern**
- Reporting and Transparency – **October 24, 2-3:30 p.m. Eastern**
- Innovative Enforcement – **November (TBD)**

For more information, please contact Sonia Altieri at saltieri@ecos.org. [Altieri]

ITRC on Long-Term Contaminant Management Using Institutional Controls

On **August 14 at 1-3:15 p.m. Eastern**, ITRC will host an online training on Long-Term Contaminant Management Using Institution Controls (ICs).

ICs are administrative or legal restrictions that provide protection from exposure to contaminants on a site. When ICs are

jeopardized or fail, direct exposure to human health and the environment can occur. After attending this training, participants will be able to describe best practices and evolving trends for IC management at individual sites and across state agency programs, improve IC reliability and prevent IC failures, and improve existing, or develop new IC management programs.

Learn more and register here. [Bodi]

U.S. EPA on Water Finance Clearinghouse

U.S. EPA, through the Water Infrastructure and Resiliency Finance Center, this week launched the Water Finance Clearinghouse, a web-based portal to help communities make informed financing decisions for their drinking water, wastewater, and stormwater infrastructure needs. The Clearinghouse contains a database with more than $10 billion in water funding sources and more than 550 resources to support local water infrastructure projects. The clearinghouse follows a crowdsourcing model and can be updated in real time based on suggestions from states, federal agencies, and other water sector stakeholders through the Contributor Portal.

States can register for webinars on how to use the Clearinghouse on **August 14, 18, 24, and 31.** All webinars will be held at **2-3 p.m. Eastern**. [Piper]

U.S. EPA on CROMERR Shared Services

EPA's Office of Environmental Information will hold an open call on its Shared Cross-Media Electronic Reporting Rule (CROMERR) Services (SCS) as a follow-up to the webinar held in May. Over the past couple of years, EPA has assisted co-regulators in implementing electronic reporting programs by developing and managing CROMERR- compliant services centrally and offering these services to co-regulators as needed to reduce time and money from developing and maintaining these services independently.

This webinar will be held on **August 16 at 2 p.m. Eastern.** U.S. EPA will present the latest enhancements and alternatives available to co-regulators and discuss the processes, roles, and resource requirements for integrating and managing SCS. Existing SCS implementers and those planning to implement new electronic reporting programs in their agencies may be interested in attending.

To register, click here. [Ortiz/Parisien]

U.S. EPA on ECHO Training

Join the Enforcement and Compliance History Online (ECHO) team for another quarterly training webinar. This webinar will focus on water facility search tools including the water facility search, effluent charts, and the pollutant loading tool.

The webinar will be held on **August 22 at 1:30 p.m. Eastern**, and registration is available here. It will be recorded for the training page if this time conflicts with your schedule. [Piper]

EPA Tools and Resources Webinar

U.S. EPA will hold its monthly Tools and Resources Webinar on **August 23 at 3-4 p.m. Eastern**. The webinar will highlight the National Stormwater Calculator (SWC), which supports local, state, and national stormwater management objectives and regulatory efforts to reduce runoff and impairment through infiltration and retention using green infrastructure practices as low impact development controls. The primary focus of the SWC is to inform site developers as to how well they can meet a desired stormwater retention target with and without the use of green infrastructure. While the SWC currently operates only as a Windows-based desktop program, a mobile application version compatible with all operating systems will be released this fall.

To join the webinar, register here. [Longsworth]

U.S. EPA on Water Issues

U.S. EPA has two ongoing webinar series addressing clean water and small water systems. The Office of Research and Development (ORD) hosts a series on water research, with the following monthly webinars scheduled:

- **August 30** - Nutrients: Weatherizing, Salinization, and Evolution of Urban Water
- **October 25** - Life Cycle Assessment as a Decision Support Tool

More information on the water research webinar series, including how to register, is available here.

In addition, ORD and the Office of Water host a monthly webinar series on small drinking water systems. Their schedule for the rest of the year is:

- **August 29** - Treatment and Control for Manganese and Iron
- **September 26** - Small Systems Research DeRISK Center
- **October 31** - State Acceptance of UV Disinfection Technologies
- **November 28** - Lead in Schools and Selecting Lead Free Fixtures
- **December 12** - Residual Chlorine and Calibration Check for Chlorine Instruments

More information on the small systems webinars, including recordings of past webinars and how to register, is available here. [Hanson]

To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: ECOS
Sent: Fri 7/14/2017 7:03:02 PM
Importance: Normal
Subject: ECOS Seeks Nominations for Secretary-Treasurer, Wyoming Governor Confirmed for Fall Meeting, & More
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ECOSWIRE

Friday, July 14, 2017

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ECOS Seeks Nominations for Secretary-Treasurer

Executive Committee Representatives for Even Regions Also Sought

ECOS is seeking nominations for the position of Secretary-Treasurer. Interested ECOS members should send an expression of interest by **August 4** to President John Linc Stine of Minnesota and copy Executive Director Alexandra Dunn. Self-nominations are appropriate. Please note "ECOS Secretary-Treasurer Nomination" in the subject line. Officer Voting will be

conducted by electronic ballot until **September 11**, the first day of the ECOS Fall Meeting.

Also at the Fall Meeting, states from even-numbered U.S. EPA Regions will elect new representatives to the Executive Committee. Under ECOS' bylaws, the current regional representative may not be re-elected to the position. States in even-numbered regions should caucus amongst themselves to identify and elect their representative and report it to Alexandra Dunn before or during the meeting. If you are emailing your decision, please note "ECOS Executive Committee Regional Representative" in the subject line. The terms for all positions begin following the Fall Meeting. [Dunn/Parisien]

Wyoming Governor, Park Superintendent Confirmed for Fall Meeting

New Agenda Available; States Should Also Plan to Attend September 13

Wyoming Governor Matt Mead is the newest keynoter confirmed for the 2017 Fall Meeting in Jackson Hole, Wyoming on *Bright Ideas: States Leading the Way*, for which early bird registration runs through **August 4**. Attendees also will be welcomed to the meeting by David Vela, Superintendent of Grand Teton National Park. A new agenda has been posted.

The interactive program ties together a number of cutting-edge ECOS initiatives of interest to a variety of stakeholders. Among the highlights, ECOS will feature outstanding programs selected for 2017 State Program Innovation Awards (see related story), unveil a new dashboard that states can use to better protect human health and the environment, and explore early wins in its Cooperative Federalism 2.0 campaign to forge an improved state-U.S. EPA partnership.

U.S. EPA officials already confirmed to attend are Assistant Deputy Administrator & Chief of Operations Henry Darwin, Senior Advisor to the Administrator for Regional & State Affairs Ken Wagner, and Acting Deputy Administrator Mike Flynn. Former ECOS member Collin O'Mara (Delaware), now President & CEO of the National Wildlife Federation, also will deliver a keynote address. And sure to be a highlight of the meeting is an evening excursion to Grand Teton National Park.

The public portion of the Fall Meeting runs all day September 11 and 12, with **states-only sessions planned until 11:15 a.m. on September 13**. These discussions will be followed by the E-Enterprise for the Environmental Leadership Council Meeting on the afternoon of September 13 and morning of September 14 until 11:30 a.m.

Attendees should make their **hotel reservations as early as possible** to take advantage of the lower of two ECOS group rates ($199 for hotel rooms versus $289 for larger accommodations). ECOS room nights include September 10, 11, and 12, with limited availability on the nights of September 13 and 14. When using the hotel reservation link, please note that Policies listed on the first reservation page apply to ECOS but that Terms & Conditions listed on a subsequent page do not apply. The special ECOS group rates are available until **August 9** or sellout of the room block, whichever is sooner.

See the Fall Meeting website for the agenda, online registration, hotel reservation link, hotel overflow suggestions, ground transportation options, and special events in Jackson listing. For more information about the agenda, sponsorship opportunities, or the hotel, contact Lia Parisien of ECOS. For additional registration information, contact Sarah Grace Longsworth of ECOS. [Parisien]

ECOS Seeks Nominations for Special Recognition Award

The ECOS President gives the ECOS Special Recognition Award annually to a member agency staff member whose dedication and contributions over a sustained period lead to the meaningful advancement of an ECOS priority during his or her tenure as President. ECOS currently is seeking nominations from its members for the 2017 award, which will be presented at the September 11-12 Fall Meeting in Jackson Hole, Wyoming. Please send your nominations to Alexandra Dunn of ECOS by **July 21.** The ECOS officers will make the final selection.

The 2016 Special Recognition awardee was Ken Zarker of Washington for his tireless work with states, Congress, and others related to reforming the Toxic Substances Control Act and his dedication to efforts to reduce toxics in the environment. In 2015, Andy Putnam of Colorado and Chris Simmers of New Hampshire received the recognition for their dedication to ECOS through involvement in and leadership of the Exchange Network and E-Enterprise. [Parisien]

Nominations Being Accepted Thru July 21 for New Round of ECOS Innovation Awards

New Request: Please Include Contact Information with Submissions

Each year, ECOS honors outstanding state initiatives with State Program Innovation Awards. The association will present a new round of awards at our **September 11–13** Fall Meeting in Jackson Hole, Wyoming.

If you have a successful new innovation to share, please send a write-up of approximately one page in Word that includes the items in the model below (which was one of last year's winning entries), including contact information. ECOS is particularly interested this year in innovations in the areas of permit streamlining and business process improvement, community outreach and engagement, and land revitalization and reuse. Nominations need not be confined to these areas, however, and are not given more weight in the selection process. Please send submissions to Megan Swanson by July 21.

In addition to receiving consideration for recognition and presentation at the Fall Meeting, submissions will be published in a special edition of *ECOS Green Report*. [Swanson]

Model Innovation Nomination
Virginia's Wetland Monitoring and Assessment Program

Description of Initiative:
Virginia has approximately one million acres of wetlands. An estimated 75 percent of these acres are palustrine vegetated wetlands, and the remaining 25 percent are estuarine wetlands. Virginia is believed to have lost about 40 percent of its original complement of pre-colonial wetlands. A study of wetland trends in Southeastern Virginia for 1994-2000 showed a net loss of 2,100 acres (1.3 percent). The actual loss of vegetated wetlands was even higher, but offset by a gain in pond and open water area.

The loss of palustrine wetlands was primarily due to conversion to uplands, while estuarine wetlands were lost through conversion to open water. Major causes of wetland loss in Virginia include conversion to other land cover types, ecosystem service modifications associated with climate change, hydrologic alterations, invasive species, fragmentation by development, crop fields, roads, fences, berms, and eliminated ecosystem services, notably habitat and water quality.

The Virginia Department of Environmental Quality (DEQ) and the Virginia Institute for Marine Science have developed a robust, science-based Wetland Monitoring and Assessment Strategy for evaluating the condition of wetlands in the Commonwealth. The overarching goal of Virginia's strategy is to devise a long-term implementation plan for a wetland monitoring and assessment program that protects the physical, chemical, and biological integrity of the Commonwealth's water resources, including wetlands.

In order to accomplish this goal, it is critical to first know the status of wetland resources in Virginia, in terms of location and extent of wetlands in each watershed, and have a general knowledge of the quality of these wetland resources. Second, the functions of wetland resources impacted through the permitting program must be accurately evaluated to determine those functions to be replaced through compensatory mitigation. It is also important to assess the degree to which the required compensatory mitigation is performing in relation to those impacted functions. The assessment method is a multi-service model that involves three levels of data collection. The method characterizes the capacity of the wetland to provide water quality and habitat services using remotely sensed data. The model application produces a relative score for each wetland for each service. The scores are then refined and calibrated by site visits to randomly selected wetlands. The relationship between structure and function is validated by intensive study of ecological service endpoints.

Results to Date:

The data collected from the assessment have been compiled into an online GIS-based wetland data viewer identified as the Wetland Condition Assessment Tool (WetCAT). WetCAT can be used to evaluate wetland condition over time, make better permitting decisions relative to cumulative impacts, avoid and minimize wetland loss, evaluate performance of compensatory wetland mitigation in replacing wetland acreage and function, and evaluate the effectiveness of the regulatory program.

Virginia's wetland monitoring and assessment program is being implemented with funds awarded through U.S. EPA's Wetland Program Development Grants to continue these efforts. DEQ has received nine grant awards from EPA for this initiative, and Virginia is recognized as one of five states leading this initiative nationally.

Contacts:

David L. Davis, CPWD, PWS
Director, Office of Wetlands & Stream Protection
Virginia Department of Environmental Quality

Michelle M. Henicheck, pWS
Senior Weland Ecologist
Virginia Department of Environmental Quality

ECOS Prepares for STEP 2017

ECOS' 2017 State Environmental Protection (STEP) meeting will take place this Monday, **July 17**. The interactive one-day gathering, themed *Reframing our Environmental Future,* will center on ECOS' *Cooperative Federalism 2.0 Paper*, released last month. See the agenda for a full list of speakers, panels, and further details. Breakfast, lunch, breaks, and a reception will be provided at the meeting. We look forward to seeing our members and friends there! [Longsworth]

House Markup of U.S. EPA FY18 Budget Reverses Some of President's Proposed Cuts

On July 12, the House Appropriations Subcommittee for Interior, Environment, and Related Agencies, which covers U.S. EPA, released its markup for an FY18 appropriations bill. The bill funds EPA at $7.5B, 7 percent or $528M below FY17 enacted levels and $1.9B above the President's FY18 budget request. Some budget highlights affecting states include:

- STAG funding totals $3.29 billion, a $240M reduction from FY17 enacted levels and $360M above the President's FY18 budget request.
- STAG grants that see increases in the bill are Diesel Emissions Reduction grants (25%), Brownfields Projects Grants (13%), and Targeted Airshed Grants (33%). Funding for Mexico Border grants is eliminated.
- The Clean Water SRF account is funded at $1.143B, down $250M or 18% below the FY17 enacted level; Drinking Water SRF funding is unchanged.
- Categorical grants to states and tribes remain flat-funded at $1.07B, with specific callouts for the Brownfields, Exchange Network, UST, and CAA sec 106 Water Quality Monitoring grant programs.
- The House bill proposes rescissions of $60M from the STAG account, $27M from the Science & Technology account, and $36M from Environmental Programs & Management.

The legislation includes funding for buyouts and voluntary separation agreements, an authorization for the EPA Administrator and the Secretary of the Army to withdraw the Waters of the United States rule, and funding prohibitions on greenhouse gas reporting and ozone NAAQS. [McAleer]

Senate EPW Advances Bodine Nomination

The Senate Committee on Environment and Public Works on July 12 voted 11-10 to advance the nomination of Susan Bodine to serve as Assistant Administrator for the U.S. EPA Office of Enforcement and Compliance Assurance. No date has been set for a full Senate vote.

During Bodine's recent confirmation hearing before EPW, Senator Bernie Sanders (I-VT) had probed the nominee about how she would handle EPA's proposed budget cuts and the emphasis on state environmental protection. Bodine responded that she agreed with ECOS' recent Cooperative Federalism 2.0 paper outlining a vision for EPA and states to work collectively to protect the environment and public health.

More information about the Wednesday's vote can be found here. [Harrison/Parisien]

U.S. EPA Releases Proposed Rule on WOTUS

U.S. EPA has released a pre-publication version of the proposed rule for "Step 1" of the process to replace the Obama-era Clean Water Rule. This first step is to reinstate policies that were in effect prior to finalization of the Clean Water Rule, and the proposed rule rescinds the definition of "waters of the United States" and replaces it with the definition used prior to issuance of the 2015 Clean Water Rule.

EPA also has released an economic analysis of the proposed rule.

The proposed rule is expected to be published in the *Federal Register* shortly. [Piper]

State News You Can Use

New York Marks Invasive Species Awareness Week

Texas Shares Tips on Living Sustainably

Member Spotlight

Two Minutes with Bill Ehm, Division Administrator, Environmental Services Division, Iowa Department of Natural Resources

What's your current job?

I lead the Environmental Services Division of the Iowa Department of Natural Resources (DNR).

How long have you been Division Administrator? What's your best experience thus far?

I have been in this position for six years. I have been a strong proponent of LEAN in our Department. It has been very rewarding to watch our staff and customers find better ways to accomplish our goals and make everyone's work easier and more focused at the same time.

How has being a member of ECOS benefitted you?
Besides making some great friends, I have appreciated learning how other states do the same business as Iowa, but in varied ways. I have brought many ideas back home to be incorporated into our work at DNR.

What is the best management advice you've received?
"Care more about the people you have than for the ones you wish you had."--Chuck Gipp, DNR Director

CONTINUED HERE

Need-to-Know News in Cooperative Federalism & Water

Cooperative Federalism 2.0 Document Featured on 'States at the Table' Website

Area of Focus: Cooperative Federalism

ECOS' Cooperative Federalism 2.0 document is featured on the States at the Table webpage, a joint project of the Council of State Governments and the Association of Air Pollution Control Agencies to provide an online comprehensive resource for state leaders from all three branches of government on opportunities to interact with federal energy and environmental agencies through Federal Advisory Committees (FACs).

By providing timely information on meetings, activities, and openings with FACs of interest, States at the Table seeks to promote federalism on environmental and energy issues and to provide interested state officials opportunities to engage with their federal counterparts. The site focuses on FACs of interest at U.S. EPA and the U.S. Department of Energy, National Oceanic and Atmospheric Administration, and U.S. Department of Interior. [Swanson]

U.S. EPA Invites Comment on Proposal to Withdraw CWA Restrictions for Pebble Mine

Area of Focus: *Water*

U.S. EPA on July 11 proposed to withdraw its July 2014 Clean Water Act Proposed Determination that would, if finalized, have imposed restrictions on the discharge of dredged or fill material associated with the potential Pebble Mine in Alaska's Bristol Bay watershed. The agency, which is seeking public comment on the proposal, is consulting with federally recognized tribal governments of the Bristol Bay region and with Alaska Native Claims Settlement Act Regional and Village Corporations with lands in the Bristol Bay watershed.

Public comments must be received on or before 90 days from the date of publication of the *Federal Register* notice. Comments will be accepted by email to ow-docket@epa.gov with docket number EPA-R10-OW-2017-0369 in the email subject line.

Read the pre-publication *Federal Register* notice. [Parisien]

ITRC

Interstate Technology and Regulatory Council

ITRC Launches New Streamlined Website

ITRC is pleased to announce the launch of its new website. The new layout is more user-friendly and streamlined, and staff can't wait to see what the ECOS and ITRC communities think.

Please feel free to contact ITRC with any comments or suggestions. Your thoughts are welcome and appreciated! [Bodi]

ERIS

Environmental Research Institute of the States

ERIS/ORD Meeting in Oklahoma

The Environmental Research Institute of the States (ERIS) Board and U.S. EPA's Office of Research and Development (ORD) convened in Oklahoma City for its annual joint meeting this week.

On Tuesday, ERIS board members, ORD staff, and executive employees of the Oklahoma Department of Environmental Quality (DEQ) drove to the Robert S. Kerr Environmental Research Center, ORD's Groundwater, Watershed, and Ecosystem Restoration laboratory in Ada, Oklahoma. Roundtable discussion covered topics including research needs, state-federal partnerships, and updates on pilot programs like C-FERST and the wildfire smoke guide. Lab scientists also provided a tour of the Kerr facilities and brief overviews of their current projects. In the evening, DEQ staff introduced meeting attendees to a Village Green Bench, a project in Oklahoma City's Myriad Botanical Gardens that measures air quality and weather conditions in real-time using new technologies built into a solar-powered park bench.

DEQ hosted the Board and ORD staff at their offices on Wednesday to conclude the meeting. The agency detailed Oklahoma's environmental challenges, and meeting attendees discussed prominent issues like perfluorinated chemicals and risk communication, and next steps for ERIS and ORD.

Oklahoma DEQ Executive Director Scott Thompson (top right) and ERIS Board Members at EPA's Village Green Bench in Oklahoma City's Botanical Garden. Top Row: Paul Mercer (ME), Bob King, Thompson; Bottom Row: ERIS President David Paylor (VA), Martha Rudolph (CO), and Bill Holman.

Upcoming Events

Calls

TIME CHANGE: ECOS, US EPA on FY 2018-19 Draft NPM Guidance Documents

ECOS' Call with EPA's Office of Water (OW) on their FY18-19 NPM guidance has been rescheduled to take place an hour

earlier than originally planned. The call will now occur next Thursday, **July 20th at 2-3 p.m. Eastern**. The conference call information is: 1-866-299-3188; Code: 202-564-0516. (Please note, the agenda that was originally distributed for this call listed an incorrect access code for the conference line. The code listed above is correct).

In late June, U.S. EPA has released its draft National Program Manager (NPM) Guidance documents for fiscal years (FY) 2018-19. The documents are available for public comment until **July 28**. This week, ECOS' Partnership and Performance Workgroup held calls with three other EPA program offices- OAR, OLEM, and OECA- to discuss their FY18-19 guidance documents.

States should send comments to Owen McAleer of ECOS by July 21 to be considered in ECOS' input on the guidances. Please contact Owen with any questions. with any questions. [McAleer]

Webinars

ITRC on Groundwater Statistics for Environmental Project Managers

An upcoming ITRC online training and associated technical document will bring clarity to the planning, implementation, and communication of groundwater statistical methods, and should lead to greater confidence and transparency in the use of groundwater statistics for site management. The training will be held **July 18 at 1-3:15 p.m. Eastern**.

Learn more and register here. [Bodi]

U.S. EPA on Beta ECHO Biosolids Data

U.S. EPA has developed an Enforcement and Compliance History Online (ECHO) facility search form for the NPDES Biosolids data coming in with the 2016 implementation of the NPDES eReporting Rule. U.S. EPA has begun collecting Biosolids Annual Reports electronically in the 42 states where it implements the federal Biosolids Program. The search allows for customized search, sort, and download of biosolids data for the first time. States are invited to see a demonstration of this feature and provide feedback prior to release to the public.

Questions on which EPA seeks feedback on are:

- Can you find the biosolids data you're seeking?
- Are there places in the search form that don't make sense?
- Once there are multiple years of annual report data available, how do you want to search and view these results?

To join a webcast on the topic on **July 19 at 1-2 p.m. Eastern**, call (866) 299-3188
and enter passcode 2025645960#. The webcast link is here.

For more information, including information on how to test the biosolids search prior to the webinar, contact Rebecca Kane at (202) 564-5960. [Graves]

U.S. EPA on ECOTOX

U.S. EPA will hold its monthly Tools and Resources Webinar on **July 19 at 3-4 p.m. Eastern**. The webinar will focus on ECOTOXicology, a comprehensive, publicly-available knowledgebase that provides chemical environmental toxicity data on aquatic life, terrestrial plants, and wildlife.

State environmental and health agencies, tribes, local governments, communities, stakeholders, and others interested in learning about predicting chemical toxicity and potential exposure effects should register here. [Longsworth]

ITRC on Geospatial Analysis for Optimization at Environmental Sites

Optimization activities can improve performance, increase monitoring efficiency, and support site decisions. Project managers can use geospatial analysis for evaluation of optimization opportunities. Unlike traditional statistical analysis, geospatial methods incorporate the spatial and temporal dependence between nearby data points, an important factor for data collected as part of an environmental investigation.

This ITRC course on **July 25 at 1-3:15 p.m. Eastern** will train state regulators and other practitioners in understanding and using geospatial analyses.

Learn more and register here. [Bodi]

U.S. EPA on Water Issues

U.S. EPA has two ongoing webinar series addressing clean water and small water systems. The Office of Research and Development (ORD) hosts a series on water research, with the following monthly webinars scheduled:

- **August 30** - Nutrients: Weatherizing, Salinization, and Evolution of Urban Water
- **October 25** - Life Cycle Assessment as a Decision Support Tool

More information on the water research webinar series, including how to register, is available here.

In addition, ORD and the Office of Water host a monthly webinar series on small drinking water systems. Their schedule for the rest of the year is:

- **July 25** - Water Loss and Distribution System Infrastructure: Leak Detection and Cost Savings
- **August 29** - Treatment and Control for Manganese and Iron
- **September 26** - Small Systems Research DeRISK Center
- **October 31** - State Acceptance of UV Disinfection Technologies
- **November 28** - Lead in Schools and Selecting Lead Free Fixtures
- **December 12** - Residual Chlorine and Calibration Check for Chlorine Instruments

More information on the small systems webinars, including recordings of past webinars and how to register, is available here. [Hanson]

U.S. EPA on C-FERST

U.S. EPA's Office of Research and Development (ORD) will host a Community-Focused Exposure and Risk Screening Tool (C-FERST) training session for ECOS and Association of State and Territorial Health Officials (ASTHO) members on **July 26 at 1-3 p.m. Eastern**. The webinar will feature slides with presenter scripts and a detailed demonstration to aid state environmental staff and health directors who are not confident in using C-FERST themselves in training others to use the tool.

ECOS and ASTHO have been working with ORD on EPA's C-FERST tool, which provides information to help users identify and learn about environmental issues in their communities, and explore exposure and risk reduction options.

If you are interested in joining, please email Sarah Grace Longsworth of ECOS. [Longsworth]

ECOS and U.S. EPA on Compliance Research

A Compliance Research Webinar Series hosted by U.S. EPA OECA's NETI and designed for ECOS members and EPA will help program administrators understand how collaboration with academics can identify effective and measureable approaches to compliance. In each of five webinars, social and behavioral scientists from top universities will present research findings on compliance monitoring, rule and permit design, reporting and transparency, and innovative enforcement. Following the presentations, participants will discuss program initiatives that can be put to the test through collaboration with academics.

The introductory webinar was held June 27. The other webinars will be held as follows:

- Monitoring – **August 9, 3-4:30 p.m. Eastern**
- Rule and Permit Design – **September 28, 2-3:30 p.m. Eastern**
- Reporting and Transparency – **October 24, 2-3:30 p.m. Eastern**
- Innovative Enforcement – **November (TBD)**

For more information, please contact Sonia Altieri of ECOS. [Altieri]

To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: ECOS
Sent: Fri 11/3/2017 6:08:41 PM
Importance: Normal
Subject: Parfitt Advances ECOS Priorities in DC, ECOS Weighs in on U.S. EPA Strategic Plan, & More
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ECOSWIRE

Friday, November 3, 2017

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ECOS President Advances State Priorities across Nation's Capital

This week, Todd Parfitt of Wyoming and ECOS staff participated in a series of meetings to share Parfitt's priorities as ECOS President and information on Cooperative Federalism 2.0 and ECOSResults.org. Parfitt met with the White House Office of Management and Budget on the outlook for state and tribal assistance grants and ECOS' budget priorities generally. Walking the halls of the U.S. Capitol, Parfitt met with Senate Environment & Public Works Committee Chair John Barrasso

(R-WY) and Rep. Liz Cheney (R-WY).

Other key meetings included discussions with EPA officials on the new Smart Sectors Program and permitting reform (see related story), and a gathering with the Executive Directors of the Association of Clean Water Administrators and Association of State Wetland Managers on advancing state assumption of the Section 404 program (see related ECOS Resolution). [Dunn/Swanson]

ECOS Expresses Support for Cooperative Federalism, E-Enterprise in U.S. EPA Strategic Plan Comments

ECOS on October 31 submitted comments on the U.S. EPA's draft FY 2018-2022 Strategic Plan. In the comment letter, ECOS offers support for the draft plan's emphasis on cooperative federalism and E-Enterprise for the Environment and suggests additional areas for agency focus, such as emergency response. The letter is accompanied by several pages of technical input on various aspects of the strategic plan.

The draft plan was released October 5 for public comment. Over the course of the 26-day public comment period, ECOS held discussions on the draft through an all-member call and correspondence and submissions from individual states.

Stay tuned for a final version of the strategic plan later this year. [McAleer]

Pruitt Announces Directive on Agency's Science Committees

On October 31, U.S. EPA Administrator Scott Pruitt issued a directive designed to ensure "independence and integrity" of agency Federal Advisory Committees (FACs). The new policy requires all FAC members to be independent from EPA and will prevent any individual who receives EPA funding from serving on one of the agency's FACs. This principle would not apply to state, tribal, or local government agency recipients of EPA grants.

The directive focuses on the following areas related to FACs: strengthening member independence; increasing state, tribal and local government participation; enhancing geographic diversity; and promoting fresh perspectives.

In addition, Pruitt announced key leadership appointments for three of the 23 committees: Michael Honeycutt of the Texas Commission on Environmental Quality will chair the Science Advisory Board; Tony Cox of Cox Associates will head the Clean Air Scientific Advisory Committee; and Paul Gilman of Covanta will serve as Chairman of the Board of Scientific Counselors. In the coming days, the full membership of these committees and boards will be announced and is expected to include state environmental agency science experts. [Swanson]

U.S. EPA Seeks Comments on Applying Federal Permitting Best Practices to State Infrastructure Permits

On October 31, EPA issued a *Federal Register* notice seeking comments on whether federal permitting best practices are generally applicable to infrastructure permits issued by delegated or authorized states as described in Title 41 of the Fixing America's Surface Transportation Act (FAST-41).

Federal "best practices" specifically refers to the January 18 document *Recommended Best Practices for Environmental Reviews and Authorizations for Infrastructure Projects* developed by the Federal Permitting Improvement Steering Council. The document includes the following best practice areas: enhancing early stakeholder engagement; ensuring timely decisions regarding environmental reviews (including exploring opportunities to expand use of general permits where appropriate); improving coordination between federal, state, and tribal agencies; increasing transparency; reducing administrative burdens by using online permit applications, eliminating unnecessary internal process steps, and conducting routine evaluations of permit processes; using geographic information systems (GIS) to expedite permitting; creating and providing training; and implementing other best practices such as use of conflict resolution and third-party neutral facilitators.

Comments are due **November 20**. States are asked to share feedback on the best practices with Beth Graves of ECOS. [Graves]

House Looks at Hurricane Response Takeaways in Two Hearings this Week

This week, the House Committee on Transportation and Infrastructure held a hearing to "explore key takeaways from this year's unprecedented hurricane season." One of the witnesses was new U.S. EPA Region 2 Administrator Pete Lopez.

Also this week, the House Committee on Energy and Commerce Subcommittee on Energy held a hearing entitled *The 2017 Hurricane Season: A Review of Emergency Response and Energy Infrastructure Recovery Efforts*. This hearing featured witnesses from the U.S. Department of Energy and U.S. Army Corps of Engineers. [Dunn]

State News You Can Use

Louisiana, U.S. EPA, and DOJ Reach Air Pollution Settlement with ExxonMobil

Colorado, U.S. EPA, and Justice Department Reach Air Pact with PDC Energy

Missouri Accepting Comments on Reducing Red Tape

Wyoming Works with U.S. EPA to Protect Streams

Virginia Reports Cleanest Air in Past 20 Years

Arkansas Staff Get 'Groovy' at Arkansas Environmental Federation Convention

Maine Announces Governor's Awards for Environmental Excellence

ECOS Resource of the Week

ITRC's Guidance on Complex Sites

Does your state agency use resources from the Interstate Technology and Regulatory Council (ITRC)? One such resource is its latest guidance document, *Remediation Management of Complex Sites*, released this week.

This guidance presents a recommended process for remediation management at complex sites, incorporating and referring to best management practices, tools, and technologies described in previous publications by U.S. EPA, the U.S. Department of Defense, ITRC, and others. The guidance also includes numerous case studies that describe real-world applications of remediation and remediation management at complex sites.

Click here to view the document. ITRC will hold its first Complex Sites online training class on **February 6, 2018 at 1-3:15 p.m. Eastern**.

ITRC is a state-led coalition of state and federal regulators, industry, and stakeholders working together to achieve regulatory acceptance of environmental technologies. Its website can be accessed at the bottom of ECOS' homepage, or here. [Bodi/Longsworth]

Need-to-Know News in Air, Water, & Environmental Justice

U.S. EPA Sets Public Hearing on CPP Repeal

Area of Focus: *Air*

U.S. EPA has announced that it will hold a public hearing on the proposed repeal of the *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (commonly known as the Clean Power Plan, or CPP) in Charleston, West Virginia on **November 28-29**. Registration will be open once the public meeting notice is published in the *Federal Register*, and all individuals wishing to speak are encouraged to register in advance.

"EPA is headed to the heart of coal country to hear from those most impacted by the CPP and get their comments on the proposed Repeal Rule," said EPA Administrator Scott Pruitt.

For additional details, see the EPA press release and EPA website for background information on the CPP. [Poole]

U.S. EPA Issues Pair of Actions on Cross-State Air Pollution

Area of Focus: *Air*

U.S. EPA on October 30 announced two actions that address cross-state air pollution for the 2008 ozone standards.

One action denies a petition filed by nine northeastern states under Section 176A of the Clean Air Act asking the agency to add eight states plus portions of Virginia to the Ozone Transport Region. EPA has determined that approaches such as those under the Clean Air Act's (CAA's) good neighbor provision will be more effective in addressing remaining ozone transport obligations for the 2008 standards. More information is available here.

In the second action, EPA issued a memo to provide supplemental information to states and the Regions. This information supports the development or review of State Implementation Plans that address the CAA's "good neighbor" provision, as it pertains to the 2008 ozone National Ambient Air Quality Standards. While this information can inform the development of these plans, the information is not a final determination regarding states' remaining obligations under the good neighbor provision, and any such determination would be made through notice-and-comment rulemaking. More information is available here. [Parisien]

U.S. EPA Signs NODA for Proposed Stays of Oil and Gas Air Rules

Area of Focus: *Air*

On November 1, U.S. EPA signed two Notices of Data Availability (NODAs) related to the agency's proposed stays of air requirements in the 2016 New Source Performance Standards for the oil and natural gas industry. EPA on June 16 had proposed a two-year stay and a three-month stay of the rule's fugitive emissions requirements, well site pneumatic pump standards, and requirements that closed vent systems be certified by a professional engineer while the agency reconsiders issues associated with these requirements.

Since proposing the stays, the agency has heard a wide range of concerns and suggestions from stakeholders both about the 2016 rule and the proposed stays. The NODAs provide information on some of these issues and seek comments to assist in developing a final rule. The information provided in the NODAs falls into two categories: challenges to implementing the requirements in the 2016 rule that would be covered by proposed stays; and the agency's legal authority to issue a stay. EPA also is providing an updated analysis of cost savings, forgone benefits, and net benefits of the proposed two-year stay.

EPA will take public comment on the NODAs for 30 days following publication in the *Federal Register*. For more information, click here. [Parisien]

U.S. EPA Recognizes 28 CWSRF Program Successes

Area of Focus: *Water*

U.S. EPA on October 31 recognized 28 clean water infrastructure projects for excellence and innovation within the Clean Water State Revolving Fund (CWSRF) program at the 2017 National SRF Workshop hosted in Indianapolis, Indiana by the Council of Infrastructure Financing Authorities. Honored projects range from large wastewater infrastructure projects to small decentralized and agriculture projects.

EPA's Performance and Innovation in the SRF Creating Environmental Success (PISCES) program celebrates innovation

demonstrated by CWSRF programs and assistance recipients. The CWSRF is a federal-state partnership that provides communities a permanent, independent source of low-cost financing for a wide range of water quality infrastructure projects. Over the past 30 years, CWSRF programs have provided more than $125 billion in financing for water quality infrastructure.

"For decades the Clean Water State Revolving Fund has supported critical water infrastructure projects that help grow the American economy and support our way of life," said Mike Shapiro, Acting Assistant Administrator for EPA's Office of Water. "These projects are a testament to the power of the Clean Water State Revolving Fund in leveraging investment to meet the country's diverse clean water needs."

More about the projects and the PISCES program can be found here. Information about an ECOS project to identify and share innovative CWSRF work can be found here. [Parisien/Piper]

U.S. EPA Announces Selections for 2017 Environmental Justice Small Grants

Area of Focus: Environmental Justice

U.S. EPA has announced the award of nearly $1.2 million in competitive grants to 36 community and tribal organizations working to address environmental justice issues in their communities. The grants enable these organizations to conduct research, provide education, and develop community-driven solutions to local health and environmental issues in minority, low-income, and tribal communities.

In an effort to increase outreach to affected communities in states and territories, the 2017 Environmental Justice Small Grants (EJSG) Program placed special emphasis on proposals from under-represented states that have been awarded three or fewer EJSGs over the last five years. Of the 36 total projects selected, 23 are from underrepresented states (64%). The agency will make final awards upon successful completion of the award application process. [Poole]

E-Enterprise for the Environment

E-Enterprise

McDonnell Appointed to E-Enterprise Leadership Council

This week, ECOS President Todd Parfitt of Wyoming appointed Pennsylvania Department of Environmental Protection Secretary Patrick McDonnell to serve on the E-Enterprise Leadership Council (EELC). McDonnell fills the state EELC vacancy created when John Stine of Minnesota ended his term as ECOS President.

ECOS thanks Stine for his EELC service and welcomes McDonnell to the leadership body. [Graves]

Member News

Tormey of Iowa Elected to ACOEL Fellowship

Congratulations to Ed Tormey, General Counsel of the Iowa Department of Natural Resources, on his election last week as a Fellow of the American College of Environmental Lawyers (ACOEL). Tormey has practiced environmental law in both the private and public sectors for 27 years and also has served as Legal Services Bureau Chief at the Ohio Environmental Protection Agency.

As reported in last week's *ECOSWIRE*, former ECOS member and President Tom Burack also was one of 20 individuals from across the nation elected last week to the College Fellowship at ACOEL's 10th anniversary meeting in Charleston, South Carolina. [Parisien]

Career Opportunities

ECOS Seeks Project Manager

ECOS is accepting applications for a Project Manager to support the work of E-Enterprise for the Environment (EE) and the National Environmental Information Exchange Network (EN). The Project Manager works with senior staff at state environmental agencies, U.S. EPA, and tribes to support the operation of the EN, and to facilitate its deeply connected and formative role in EE.

To apply for this position, send a resume and cover letter here by November 30 with subject "Application for Project Manager."

See more information here. [Longsworth]

Upcoming Events

Meetings

Butler of Ohio to Participate in Disaster and Public Safety Brown Bag on the Hill

The Sea Grant Association invites interested attendees to a lunchtime briefing, *Using Science and Outreach to Assist State and Local Decision Makers in Disaster Preparedness and Public Safety*. ECOS member Craig Butler of Ohio will participate in the lunchtime discussion, which is sponsored by Congressmen Lee Zeldin of New York and Joe Courtney of Connecticut.

The event will be held **November 8 at 12-1:30 p.m.** in the Rayburn House Office Building. RSVP by November 3 to Joel Widder. [Piper]

ECOS Calls

November, December All-Member Calls

ECOS will hold its remaining two All-Member Monthly Calls in 2017 on:

- **November 16, 4-5 p.m. Eastern** on science and research
- **December 14, 3-4 p.m. Eastern** on data and analytics

Please mark your calendars now. An agenda with dial-in information will be emailed to all ECOS members prior to the call. [Swanson]

Superfund Workgroup

The ECOS Superfund Workgroup will hold its next call on **November 27 at 2:30-3:30 p.m. Eastern** to continue state-U.S. EPA discussion of implementing the recommendations of the EPA Superfund Task Force. The workgroup is chaired by ECOS Waste Committee Chair Scott Thompson, Director of the Oklahoma Department of Environmental Quality, and has the regular participation of EPA Task Force Chair Kell Kelly, Senior Advisor to the Administrator, and other EPA leaders.

The call will include a report-out on Superfund discussions at the recent ASTSWMO Annual Meeting by ASTSWMO CERCLA/Brownfields Subcommittee Chair Amy Brittain of Oklahoma and former ASTSWMO Past President Bonnie Buthker of Ohio. Call participants will provide input on the solutions proposed.

For more information, please contact Lia Parisien of ECOS. [Parisien]

Shale Gas Caucus

The ECOS Shale Gas Caucus (SGC) will kick off its Phase 3 cross-media webinar series on **December 6 at 2-3 p.m. Eastern** with a discussion of preventing produced water spills and leaks. Moderated by SGC Co-Chairs Dave Glatt of North Dakota and Martha Rudolph of Colorado, the call will feature Scott Anderson and Dan Mueller of the Environmental Defense Fund and Roy Hartstein of Southwestern Energy. Jim Kenney of U.S. EPA's Office of Enforcement and Compliance Assurance will follow with an announcement of an SGC success story in the area of produced water.

For more information, please contact Lia Parisien of ECOS. [Parisien]

Webinars

California on Safer Consumer Products

California's Department of Toxic Substances Control (DTSC) will hold a Safer Consumer Products program public workshop on lead-acid batteries and alternatives on **November 6** in Sacramento, California. The event will be broadcast via webinar and will cover the various uses of lead-acid batteries, the regulatory landscape they face, lithium-iron-phosphate batteries as a potential alternative in vehicles, automobile manufacturer perspectives, and issues such as recycling.

This information is being gathered as part of DTSC's work to evaluate whether lead-acid batteries should be listed as a Priority Product under California's Safer Consumer Products regulations. Public comments and questions are welcome.

Register for the in-person or webinar and download the agenda and event announcement. [Longsworth]

U.S. EPA and the Army Corps on WOTUS by Sector

U.S. EPA and the U.S. Army Corps of Engineers have announced ten teleconferences to hear from stakeholders their recommendations for revising the definition of "Waters of the United States" under the Clean Water Act. The first nine teleconferences will be tailored to specific industries, as follows, and the tenth will be open to the public at large.

The teleconferences will run throughout the fall on **Tuesdays at 1-3 p.m. Eastern** as follows:

- **November 7** scientific organizations and academia;
- **November 14** stormwater, wastewater management and drinking water agencies; and
- **November 21** general public. [Piper]

ECOS and U.S. EPA on Compliance Research Part 5

Part 5 of the Compliance Research Webinar Series entitled *Innovative Approaches to Foster Compliance – the Role of Deterrence* will be held on **November 9 at 1-2:30 p.m. Eastern**.

Dr. Sarah Stafford, a Professor at the College of William and Mary working in Economics, Public Policy, and Law, will present the basic theories of compliance and deterrence and the findings of social science research on what techniques are most effective. She also will present some innovative approaches being used in programs across the U.S. to encourage facilities to increase voluntary compliance and to decrease inadvertent violations.

The Compliance Research Webinar Series, hosted by the National Enforcement Training Institute of the U.S. EPA Office of Enforcement and Compliance Assurance and designed for ECOS and U.S. EPA, helps program administrators understand how collaboration with academics can identify effective and measureable approaches to compliance.

For more information, please contact Sonia Altieri of ECOS. [Altieri]

ITRC on Long-term Contaminant Management Using Institutional Controls

On **November 14 at 1-3:15 p.m. Eastern**, the Interstate Technology and Regulatory Council (ITRC) will host a free online training on institutional controls (ICs), which are administrative or legal restrictions that provide protection from exposure to contaminants on a site.

After attending the training, participants will be able to describe best practices and evolving trends for IC management at individual sites and across state agency programs; improve IC reliability and prevent IC failures; improve existing, or develop new, IC management programs; identify the pros and cons about differing IC management approaches; and more.

Learn more and register here. [Bodi]

U.S. EPA on Drinking Water Issues

U.S. EPA's Office of Research and Development and the Office of Water host a monthly webinar series on small drinking water systems. Their schedule for the rest of the year is:

- **November 15** - National Stormwater Calculator for Managing Runoff
- **November 28** - Lead in Schools and Selecting Lead Free Fixtures
- **December 12** - Residual Chlorine and Calibration Check for Chlorine Instruments

More information on the small systems webinars, including recordings of past webinars and how to register, is available here. [Hanson]

U.S. EPA ORD on Cyanobacteria Monitoring

U.S. EPA's Office of Research and Development will hold its next monthly Tools and Resources webinar on **November 15 at 3-4 p.m. Eastern**.

The webinar will focus on monitoring cyanobacteria with satellites, highlighting how federal agencies (EPA, NASA, NOAA and USGS) are collaborating to use real-world satellite applications that support environmental management of U.S. lakes by quantifying cyanobacterial harmful algal blooms and related water quality parameters. This webinar will also address provisional satellite derived cyanobacteria data and three software tools available to state environmental and health agencies for review and testing as part of the Cyanobacteria Assessment Network (CyAN).

Register here. [Longsworth]

ITRC on PVI: Fundamentals of Screening, Investigation, and Management

On **November 16 at 1-3:15 p.m. Eastern**, the Interstate Technology and Regulatory Council (ITRC) will host a free online training on petroleum vapor intrusion (PVI), the process by which volatile petroleum hydrocarbons released as vapors from light nonaqueous phase liquids, petroleum-contaminated soils, or petroleum-contaminated groundwater migrate through the vadose zone and into overlying buildings.

After attending this training, participants should be able to determine when and how to use the ITRC PVI document at their sites; describe the important role of biodegradation impacts on the PVI pathway (in contrast to chlorinated solvent contaminated sites); value a PVI conceptual site model and list its key components; and more.

Learn more and register here. [Bodi]

NIH on Wildfire Risk Communication and Health Effects

On **November 17 at 1-2 p.m. Eastern**, the National Institutes of Health will host a webinar on the impacts of wildfires on the health of vulnerable individuals and on communities exposed periodically to such events.

The presentations will cover how environmental exposures associated with wildfires affect human health, as well as approaches being used to develop targeted risk communication about wildfires for a variety of audiences.

Register here.

To: Dunham, Sarah[Dunham.Sarah@epa.gov]
Cc: Harvey, Reid[Harvey.Reid@epa.gov]
From: Prabhu Dayal
Sent: Wed 2/7/2018 9:53:38 PM
Subject: EPA Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.
2018EUEC-Brochure.pdf

Dear Reid,

It is a pleasure inviting you back to EUEC 2018 in San Diego, California. I would also like to thank Sarah and hope she can make it next year in San Diego.

Attached is the preliminary program brochure.

Please let me know if you need anything.

Thank you.

Prabhu

With best regards,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

info@euec.com

Phone (520) 615 3535

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HOME | BROCHURE | SPEAK | EXHIBIT | REGISTER

From: Dunham, Sarah [mailto:Dunham.Sarah@epa.gov]
Sent: Wednesday, February 7, 2018 2:04 PM
To: Prabhu Dayal <pdayal@euec.com>
Cc: Harvey, Reid <Harvey.Reid@epa.gov>

Subject: RE: Request Sarah Dunham as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hi Prabhu-

Thank you for the invitation to speak at the upcoming conference. As I just mentioned on the phone, Reid Harvey, the Director of the Clan Air Markets Division, is able to be the EPA keynote speaker at the upcoming conference. I am copying him on this note to connect the two of you for further planning purposes.

Thanks again for reaching out to us,

Sarah

From: Prabhu Dayal [mailto:pdayal@euec.com]
Sent: Friday, February 02, 2018 11:22 AM
To: Dunham, Sarah <Dunham.Sarah@epa.gov>
Cc: EUEC Info <info@euec.com>
Subject: Request Sarah Dunham as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.
Importance: High

Dear Sarah,

Sorry I missed you on the phone. I would like to request you to be our EPA keynote speaker on March 5, 2018 in San Diego, California.

I did request EPA AA Bill Wehrum, but he is not able to make it.

Attached is the Preliminary program for EUEC 2018.

As you are familiar with EUEC for so many years, it would be fantastic for you to be our keynote speaker.

Thank you.

Prabhu

With best regards,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

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From: Prabhu Dayal
Sent: Friday, January 12, 2018 1:41 PM
To: Lewis, Josh <Lewis.Josh@epa.gov>
Cc: EUEC Info <info@euec.com>; Wehrum.Bill@epa.gov
Subject: FW: Speaker request form for EPA AA Bill Wehrum as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hi Josh,

Attached is the info I sent to Isabel, re OAR AA form for AA Bill Wehrum.

Bill is familiar with EUEC, and was a speaker even last year at EUEC 2017.

Let me know if you need anything else.

Thank you.

Prabhu

With best wishes for the New Year,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

info@euec.com

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From: Prabhu Dayal
Sent: Wednesday, January 10, 2018 3:44 PM
To: DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Cc: EUEC Info <info@euec.com>
Subject: Speaker request form for EPA AA Bill Wehrum as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hi Isabel,

Attached is the speaker request form for Bill Wehrum, along with the Brochure for EUEC 2018.

Thank you.

Prabhu

With best wishes for the New Year,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

info@euec.com

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HOME | BROCHURE | SPEAK | EXHIBIT | REGISTER

From: DeLuca, Isabel [mailto:DeLuca.Isabel@epa.gov]
Sent: Wednesday, January 10, 2018 9:06 AM
To: EUEC Info <info@euec.com>
Subject: RE: Invite EPA AA Bill Wehrum as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hi Prabhu,

As a part of the request for Bill to speak at the EUEC in San Diego on March 5, could you please fill out the attached speaker request form?

Many thanks,

Isabel DeLuca

Deputy Director, Communications

Office of Air and Radiation, US EPA

(202) 343-9247

From: Lewis, Josh
Sent: Tuesday, January 09, 2018 3:37 PM

To: EUEC Info <info@euec.com>
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>; Wehrum, Bill <Wehrum.Bill@epa.gov>; Millett, John <Millett.John@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Subject: RE: Invite EPA AA Bill Wehrum as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hi Prabhu,

Acknowledging receipt of your email and the invitation and looping in a few others. We'll review and be in touch.

Josh

From: EUEC Info [mailto:info@euec.com]
Sent: Tuesday, January 09, 2018 2:20 PM
To: Lewis, Josh <Lewis.Josh@epa.gov>
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>; Wehrum, Bill <Wehrum.Bill@epa.gov>; EUEC Info <info@euec.com>
Subject: RE: Invite EPA AA Bill Wehrum as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.
Importance: High

Dear Josh,

Sorry I couldn't reach you on the phone.

Listed below is our invite to Mr. Bill Wehrum to be our keynote speaker at EUEC 2018 March 5 in San Diego California.

Can you please help confirm.

My cell phone is **Ex. 6**

Thank you.

Prabhu

With best wishes for the New Year,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

info@euec.com

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From: Prabhu Dayal
Sent: Thursday, December 14, 2017 2:23 PM
To: Pruitt.Scott@epa.gov
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>; Wehrum.william@epa.gov; wwehrum@hunton.com; EUEC Info <info@euec.com>
Subject: Invite EPA Administrator. Scott Pruitt as Keynote Speaker at USA's Largest Energy Utility Environment Conference - EUEC 2018: March 5, San Diego, California.

Hon. Scott Pruitt

Administrator, U.S. EPA

Washington, DC 20004

Dear Administrator Pruitt,

It is an honor and privilege to invite you to be our keynote speaker at EUEC 2018 - the 21st annual event, USA's largest Energy Utility Environment Conference to be held March 5 to 7, 2018 in San Diego, CA, with 2,000 delegates, 400 speakers, and 200 exhibits.

For the last 10 years, we have been fortunate to have with heads of EPA, DOE, and the CEO of a major Coal Electric Utility, and an NGO speak in the keynote session of EUEC, as shown listed below.

- US EPA Administrator or AA (Gina McCarthy, Janet McCabe)
- US DOE the Assistant or Deputy Secretary (Chris Smith, David Mohler)
- CEO of major coal fired electric utility, (Southern, Duke, AEP, Ameren, PNM, Allete, TEP, APS, SRP)
- Head of a NGO (CDP, NRDC, EDF)

I am copying Mr. Bill Wehrum, AA, US EPA Office of Air & Radiation, and his assistant, who have participated in the past and familiar with EUEC to help coordinate.

We plan to make your presentation most valuable and rewarding to the US EPA, and the 2,000 energy and utility professionals attending EUEC, and an additional 3,000 attending the Clean Car Expo promoting alternate fuel vehicles.

With best regards,

Prabhu Dayal, PhD, P.E.

Chairman, EUEC

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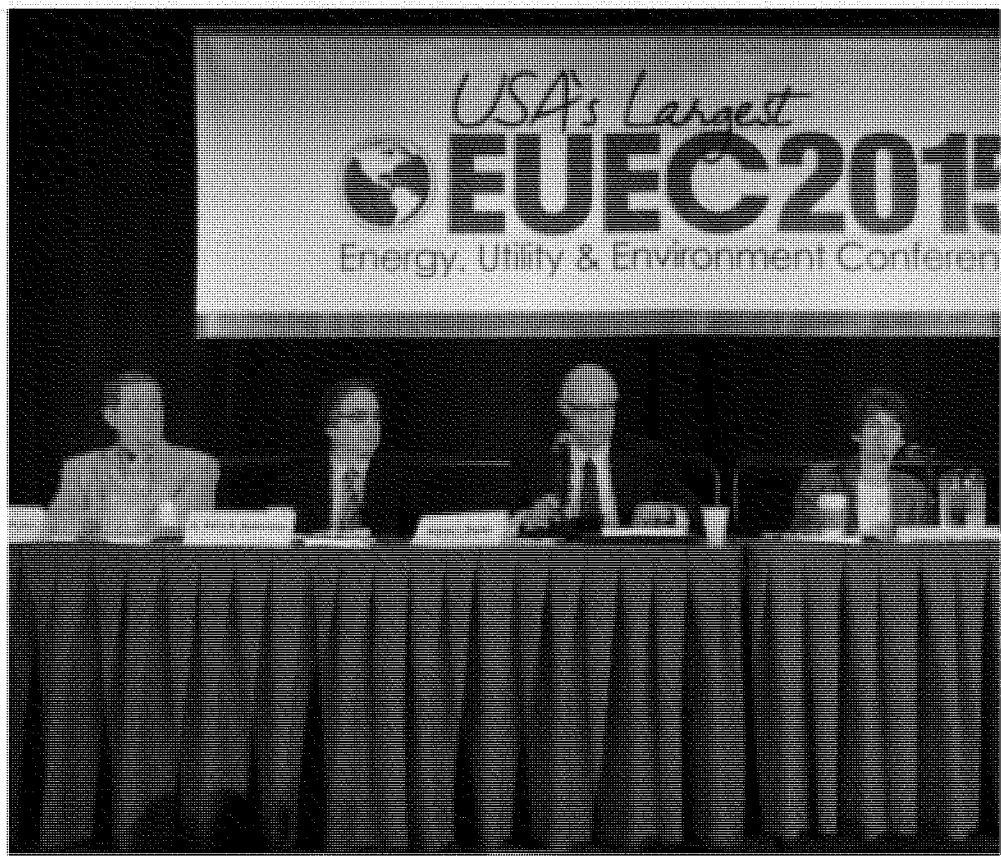
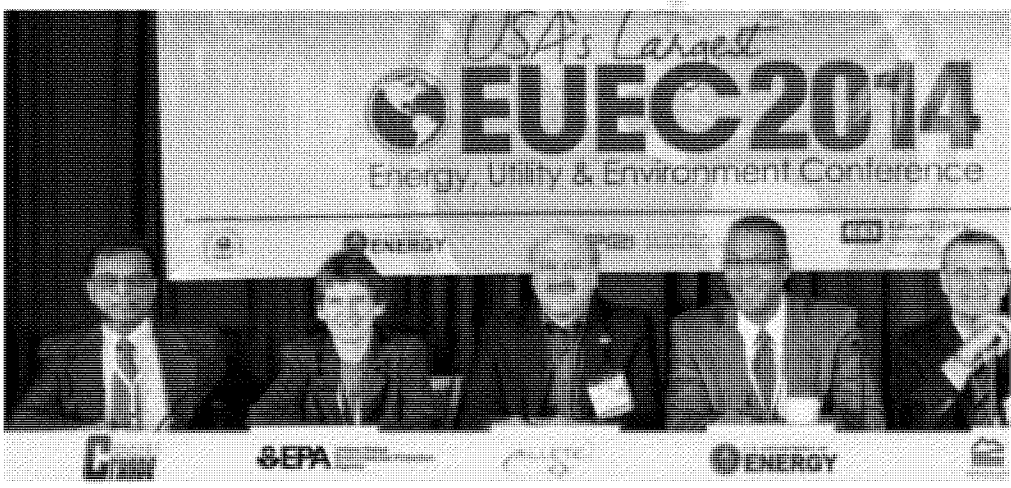


EUEC2015 Keynote Speakers from left to right: Len Hering, RADM, USN(Ret.); Dr. Barry Wallerstein, Executive Officer, South Co
President and CEO, Ameren Corporation; Janet McCabe, Acting Assistant Secretary, US EPA;



EUEC2014 Keynote Speakers from left to right: Dr. Prabhu Dayal, EUEC Chair; Janet McCabe, Acting Assistant Secretary, US EPA;
Assistant Secretary, US DOE; Phil Sharp, President, Resources for the Future; Dr. Bryan Hanneg

USAs Largest

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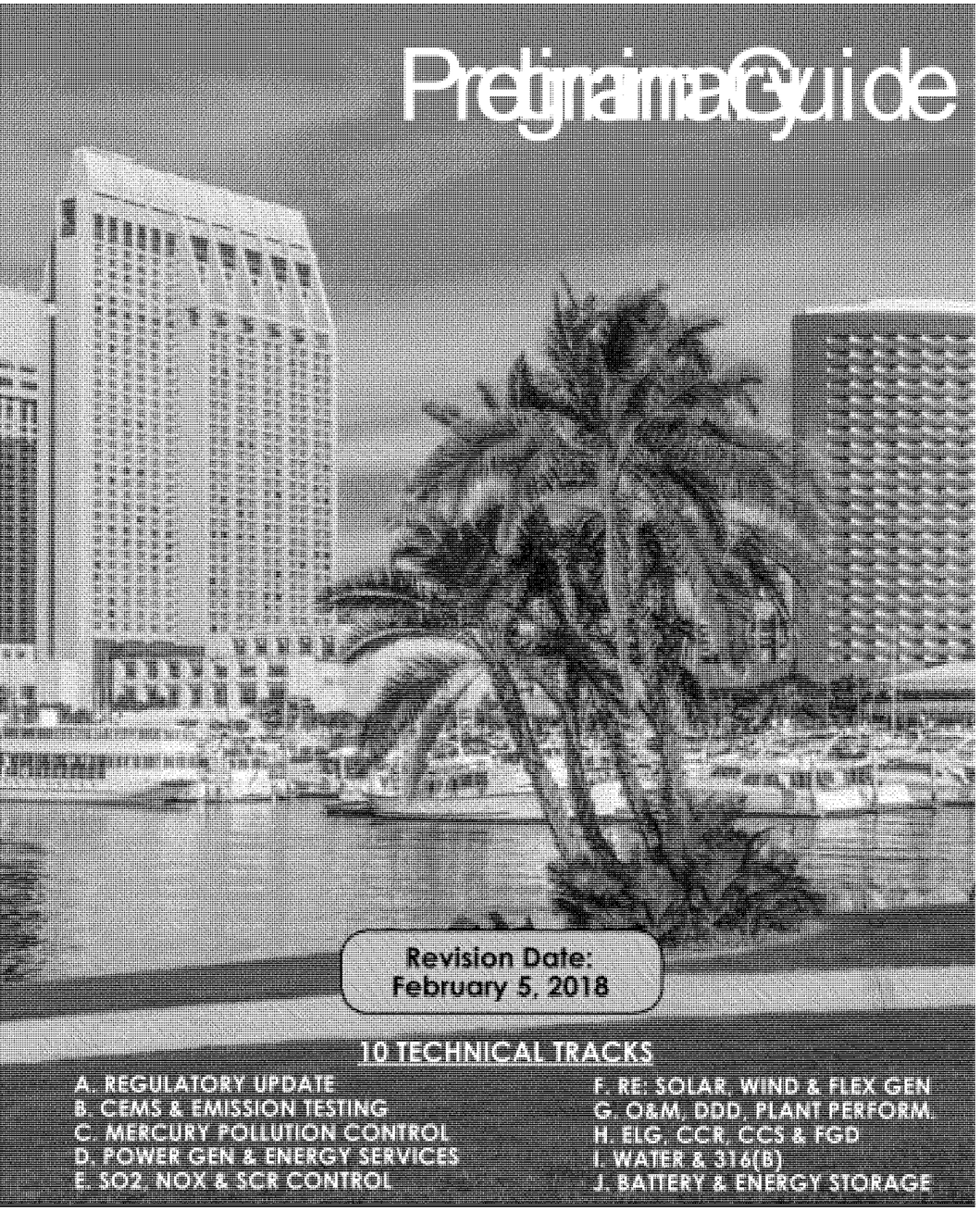
San Diego Convention Center

111 W Harbor Dr, San Diego, CA 92101



10 TECHNICAL TRACKS

A. REGULATORY UPDATE
B. CEMS & EMISSION TESTING
C. MERCURY POLLUTION CONTROL
D. POWER GEN & ENERGY SERVICES
E. SO2, NOX & SCR CONTROL
F. RE: SOLAR, WIND & FLEX GEN
G. O&M, DDD, PLANT PERFORM.
H. ELG, CCR, CCS & FGD
I. WATER & 316(B)
J. BATTERY & ENERGY STORAGE

Keynote Panelists:

EPA	ENERGY	SDGE	EUEC
William Wehrum - Invited	Rick Perry - Invited	Jeff Martin - Invited	Prabhu Dayal

EUEC | P.O. Box 66076, Tucson, AZ 85728 | (p) 520.615.3535 | (f) 602.296.0199 | info@euec.com | www.euec.com

What is EUEC?

2,000 ATTENDEES | 400 SPEAKERS | 150 EXHIBITS

EUEC 2018: The 21st Annual Energy, Utility & Environment Conference, is USA's largest professional networking & educational event of its kind, held March 5 to 7, 2018, at the San Diego Convention Center, San Diego, CA.

EUEC registrants get free admission to the Clean Car Expo(CCE) that is co-located across the hall in the Sails Pavilion. The Expo is held in the evenings from 6 to 9 pm on March 5 nd 6th, after EUEC ends each day at 6 pm.

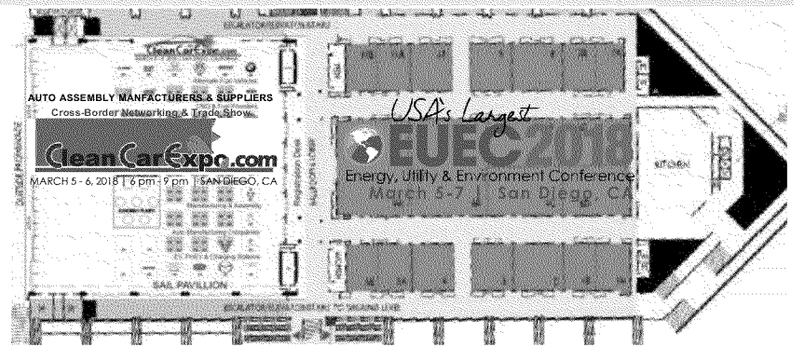
The Clean Car Expo showcases the latest in alternate fuel vehicles, displayed under one roof. Auto manufacturers and assembly plants from Mexico market and network with suppliers of US technology, including battery and storage. See --

www.CleanCarExpo.com

LAST 4 EXHIBIT BOOTHS AVAILABLE AT DISCOUNT

e-mail info@euec.com

http://www.euec.com/online-booth-reservation/



CLEAN CAR EXPO	EUEC2018
2,000 Attendees	**2,000 Attendees**
Mon, 3/5 - 6 pm to 9 pm	9 am to 6 pm
Tue. 3/6 - 1 pm to 9 pm	9 am to 6 pm
Wed. 3/7/18	9 am to 12 pm

REGISTRATION COST INCLUDES:

- Admission to 400+ presentations in 10 track rooms
- 13 food and beverage tickets ($300 value)
- 8 networking breaks & meals served in exhibit halls
- Flash Drive containing 400 presentations with audio ($495 value)
- Free spouse registration and admission to Clean Car Expo

REGISTRATION COST	Current	Feb 9	Feb 15	On-Site
Attendee - Registration	**$995**	**$1095**	**$1195**	**$1395**
Exhibitor/Speaker/Gov't/Utility	**$795**	**$895**	**$795**	**$1395**
VIP	**$695**	**$795**	**$895**	**$995**

Media Partners

EUEC 2018 SCHEDULE

Sunday | March 4th		
7:00 am - 7:00 pm	Registration	
12:00 pm - 6:00 pm	Exhibit Set-up	
5:00 pm - 7:00 pm	Welcome Reception	

Monday | March 5th		
7:00 am - 7:00 pm	Registration	
12 pm - 6:00 pm	Exhibits Open	
9:00 am - 12:00 pm	Plenary Session	
12:00 pm - 1:00 pm	**Networking Lunch 1**	
1:00 pm - 3:00 pm	Tech Session 1	
3:00 pm - 3:30 pm	**Networking Break 2**	
3:30 pm - 5:30 pm	Tech Session 2	
4:00 pm - 6:00 pm	**Networking Reception 3**	
6:00pm - 9 pm	**Clean Car Expo**	

Tuesday | March 6th		
9:00 am - 6:00 pm	Exhibits Open	
7:30 am - 9:30 am	Tech Session 3	
9:30 am - 10:00 am	**Networking Break 4**	
10:00 am - 12:00 pm	Tech Session 4	
12:00pm - 1:00 pm	**Networking Lunch 5**	
1:00 pm - 3:00 pm	Tech Session 5	
3:00 pm - 3:30 pm	**Networking Break 6**	
3:30 pm - 5:30 pm	Tech Session 6	
4:00 pm - 6:00 pm	**Networking Reception 7**	
6:00pm - 9 pm	**Clean Car Expo**	

Wednesday | March 7th		
9:00 am - 12:00 pm	Exhibits Open	
7:30 am - 9:30 am	Tech Session 7	
9:30 am - 10:00 am	**Networking Break 8**	
10:00 am - 12:00 pm	Tech Session 8	

CHAIR/SPONSOR/ADVISORY BOARD

Chairs/Sponsors/Advisory Board are responsible for:

- overall design of program agenda & session topics,
- invite, select and place speakers and design session,
- review abstracts for duplication and QC,
- moderate the session, and ensure speakers are timely.

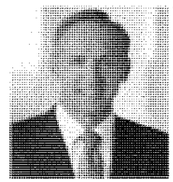
CONTACT: info@euec.com

Keynote

Monday, March 5th, 2018. 9:00 AM - 12:00 PM
San Diego Convention Center | 111 W. Harbor Dr. | San Diego, CA.

TBD
RICK PERRY (INVITED) — 9:00AM - 9:30AM
Secretary
U.S. Department of Energy
U.S. DEPARTMENT OF ENERGY

TBD LIAM WEHRUM (INVITED) — 9:30AM - 10:00AM
Assistant Adminsistrator - EPA's Office of Air and Radiation
U.S. Environmental Protection Agency
EPA United States Environmental Protection Agency



TBD
JEFF MARTIN (INVITED) — 10:00AM - 10:30AM
CFO and Executive Vice President
Sempra Energy
SDGE A Sempra Energy utility

TBD
TBD— 10:30AM - 11:00AM
NGO - Non Government Organization
NGO

HIGHLIGHTS OF EUEC2018
DR. PRABHU DAYAL — 11:00AM - 11:30AM
Chairman | EUEC
EUEC

SPEAKER FORMAT

- All speakers limited to 20 minutes using PowerPoint
- Submit abstract online and select track and session of choice
- Each session is 2 hours long with 6 speakers and 2 co-chairs

Mission Statement

EUEC facilitates information exchange and fosters cooperation between industry, government, and regulators for the protection of our environment and energy security.

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TRACK A ADVISORY BOARD

In the 21 year history of EUEC, this track is one of the most popular, with capacity attendance. Presentations are made by leaders and experts on current regulations that impact the electric utility industry. Updates on upcoming regulations, and discussions from regulatory and industry perspectives. Practical examples and case histories provide senior utility executives and decision makers options and strategies for compliance.

Monday | 1PM - 3PM

A1. REGULATORY UPDATE - CAA & EPA

A1.1 ELECTRIC ENERGY AND CLEAN AIR ACT, 2018 - 2020
Co-Chair - John Kinsman, Sr. Director - Environment, Edison Electric Institute

A1.2 RECONSIDERING EPA RECONSIDERATIONS
Session Sponsor & Co-Chair - Jay Holloway, Partner, Williams Mullen

A1.3 FURTHER TRIALS AND TRIBULATIONS OF THE GUIDELINE ON AIR QUALITY MODELS
Gale Hoffnagle, Sr. Vice President & Technical Director, TRC Environmental Corporation

A1.4 EPA'S REGULATORY AGENDA UNDER THE TRUMP ADMINISTRATION
David Jordan, Partner, ERM

A1.5 ZERO EMISSIONS CREDITS - ADDRESSING NUCLEAR GENERATION-AT-RISK
Kenneth Dubin, Senior Electric Analyst, U.S. Energy Information Administration (EIA)

A1.6 THE CURIOUS CASE OF CAA CIVIL PENALTY INFLATION
Kurt Kissling, Attorney, Pepper Hamilton LLP

Monday | 3:30PM - 5:30PM

A2. ELECTRIC UTILITY CHALLENGES

A2.1 CLEAN AIR ACT INITIATIVES IN THE TRUMP ERA: WHAT TO EXPECT
Alexandra Bromer, Partner, Perkins Coie LLP

A2.2 ENERGY & AIR QUALITY REGULATION UNDER THE TRUMP ADMINISTRATION
Scott Osbourn, Principal, Trinity Consultants

A2.3 AIR REGULATORY CHALLENGES FACING THE NATION'S ELECTRIC COOPERATIVES
Daniel Chartier, Regulatory Director, Environ. Policy, Nat'l Rural Electric Coop. Assoc.

A2.4 POLICY SHIFTS AND MARKET DIRECTIONS
Marc Chupka, Principal, The Brattle Group

A2.5 DEVELOPING A FRAMEWORK FOR INTEGRATED ENERGY NETWORK PLANNING
Adam Diamant, Technical Executive, EPRI; Tom Wilson and Daniel Brooks

A2.6 REPEAL? REPLACE? THE FUTURE OF THE CLEAN POWER PLAN & GHG REGULATION
Allison Wood, Partner, Hunton & Williams LLP

Tuesday | 7:30AM - 9:30AM

A3. NAAQS, SSM & CAA

A3.1 MODELING APPROACHES FOR STARTUP, SHUTDOWN AND MALFUNCTION EVENTS
Robert Paine, Associate Vice President, AECOM; Chris Warren

A3.2 PHOTOCHEMICAL MODELING W/ CAMX FOR OZONE INTER-PRECURSOR TRADING
Qi Zhang, Sr. Air Quality Engineer, Providence Eng. & Env. Group; James Red

A3.3 TAKING THE CAA INTO THE 21ST CENTURY AND BEYOND: A PROPOSAL
Bill Smalling, Attorney, The Law Office of C. William Smalling, PC

A3.4 OZONE AND PM2.5 - SIL'S, MERPS, AND MORE
Richard Hamel, Senior Air Quality Meteorologist, ERM

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

Tuesday | 10AM - 12PM

A4. NSR

A4.1 NSR 2018 - UPDATE AND RECENT DEVELOPMENTS
Co-Chair - Ken Weiss, Partner, ERM

A4.2 THE UTILITY NEW SOURCE REVIEW ENFORCEMENT INITIATIVE–ONE LAST UPDATE?
Makram Jaber, Partner, Hunton & Williams LLP

A4.3 DECONSTRUCTING NSR ENFORCEMENT: MINIMIZING PLANT EXPOSURE
Eric Hiser, Partner, Jorden Hiser & Joy, PLC

A4.4 PSD PERMITTING UNDER THE 2017 GUIDELINE ON AIR QUALITY MODELS
J. Stephen Beene, Sr. Consultant, Trinity Consultants; N. Sule & C. Otto Chambers

A4.5 IS NSR REFORM POSSIBLE? SETTLEMENT TRENDS AND YOUR REAL NSR RISK
Liz Williamson, Attorney, Williams Mullen

A4.6 THE FUTURE OF NEW SOURCE REVIEW - OPTIONS AND PROSPECTS FOR REFORM
Joel Beauvais, Partner, Latham & Watkins

Tuesday | 1:00PM - 3:00PM

A5. UTILITY IMPACTS & EPA COMPLIANCE

A5.1 TURNING THE BATTLESHIP: HOW THE TRUMP EPA IS CHARTING A NEW COURSE
Session Sponsor & Co-Chair - Mack McGuffey, Partner, Troutman Sanders LLP

A5.2 WHAT WILL COOPERATIVE FEDERALISM MEAN IN THIS ADMINISTRATION?
Shannon Broome, Partner, Hunton & Williams LLP

A5.3 CORONADO GENERATING STATION REGIONAL HAZE BART ALTERNATIVE
Bill McClellan, Manager, Air Quality Services, Salt River Project

A5.4 BACK TO BASIC ON COMPLIANCE
Claudette Horn, Sr. Manager, Environmental Services, PNM Resources

A5.5 TBD ???
Angela Levin, Partner, Troutman Sanders LLP

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TRACK | A | REGULATORY UPDATE

ROOM 1

Tuesday | 3:30PM - 5:30PM

A6. PERMITS & COMPLIANCE

A6.1 THE PIECEMEAL APPROACH TO THE CLIMATE REGULATION PUZZLE
Megan Berge, Partner, Baker Botts LLP

A6.2 STRATEGIC ANALYSIS OF GHG PROGRAMS: MITIGATION AND ADAPTATION
Jesse Frederick, Vice President, WZI, Inc.

A6.3 CHALLENGES WITH PERMITTING FOR INCREASED CAPACITY
Mary Hauner-Davis, Manager, Air/Noise Department, Burns & McDonnell Engineering

A6.4 PERMITTING COMBINED CYCLE COMBUSTION TURBINES - THEN AND NOW
J. Dwain Kincaid, Senior Consultant, Air Quality Services, LLC

A6.5 WINGING IT - CONFUSION AND COMPLIANCE WITH NESTING BIRD REGULATIONS
David Lee, Sr. Biologist, Davey Resource Group

A6.6 MINIMIZING ENVIRONMENTAL RISKS ON TRANSMISSION LINE PROJECTS
Claire Kwiatkowski, Environmental Associate, Sargent & Lundy

Wednesday | 7:30AM - 9:30AM

A7. AIR PROGRAMS & PERMITTING

A7.1 SCE SANTA BARBARA EM. GENERATOR PROJECT - PART 1; SITING & PERMITTING
Michelle Nuttall, Sr. Project Manager, Southern California Edison; Sara Head, Yorke Eng.

A7.2 SCE SANTA BARBARA EMERGENCY GENERATOR PROECT - PART 2: PROPOSITION 65
Sara Head, Principal Scientist, Yorke Engineering; Michelle Nuttall, Southern Cali. Edison

A7.3 PERMITTING CHALLENGES FOR RICE GENERATION TO SUPPLEMENT RENEWABLE ENERGY SOURCES
Mary Kaplan, Air Quality Meteorologist, AECOM; Chris Warren and Robert Paine

A7.4 BEST PERMITTING PRACTICES - A MAP FOR PERMITTING COMBINED CYCLE POWER
Leah Blinn, National Air Practice Lead, APTIM

Wednesday | 10AM - 12PM

A8. REGULATORY IMPACTS

A8.1 WHAT'S IT TAKE TO CHANGE YOUR MIND IF YOU ARE THE GOVERNMENT?
Charles Knauss, Partner, Hunton & Williams LLP

A8.2 REGULATORY DEVELOPMENTS IN THE TRUMP ADMINISTRATION
Michael Goo, Regulatory Counsel, ICAC

A8.3 2015 OZONE NAAQS – IMPLEMENTATION UPDATE AND IMPACTS
Arijit Pakrasi, Director, APTIM

A8.4 NSR OFFSETS FOR NEW POWER PROJECTS IN SOUTH COAST; COST AND AVAILABILITY
Bhaskar Chandan, AQ Analysis and Comp. Supervisor, South Coast Air Quality Mgmt.; Andrew Lee

A8.5 GAS TURBINE REGULATORY REGULATIONS AND ENFORCEMENT CASE STUDIES
Ben Sehgal, Senior Staff Engineer, California Air Resources Board

TRACK | B | CEMS & EMISSION TESTING

ROOM 2

TRACK B ADVISORY BOARD

An excellent "must attend" training session for experts and operators at CEMs. This Track includes EPA policy and procedures for accurate monitoring, reporting, and auditing of emissions pursuant to Part 75 of the Acid Rain Program and the Clean Air Interstate Rule. Presentations on how to submit monitoring plans, QA/QC tests, and emissions data using the Emissions Collection and Monitoring Plan System (ECMPS).

Other expert presentations and programs include MATS, egrid, RATA, Appendix D & E, Electronic Monitoring data, QA/QC program for Cylinder gases. AQ and fenceline monitoring, and modeling.

Monday | 1PM - 3PM

B1. CEMS & PEMS

B1.1 CONTINUOUS EMISSION MONITORING SYSTEM(CEMS) PROGRAM BEST PRACTICES
Eric Wiley, Managing Consultant, Trinity Consultants

B1.2 LASER DISPERSION SPECTROSCOPY AND CEM APPLICATIONS
Graham Leggett, Vice President, Product Management, MIRICO Ltd.

B1.3 PEMS DEPLOYMENT IN SAUDI ARABIA
Brian Swanson, President, CMC Solutions; Jessica Palmer

B1.4 TDL MONITORING
Gary Cacciatore, Business Development Manager, Cemtek Environmental

B1.5 CEMS MAINTENANCE
John Kelley, Vice President of Business Development, AMP-Cherokee

Monday | 3:30PM - 5:30PM

B2. CEMS & TESTING

B2.1 TESTING MANAGEMENT FOR RATA, PERMIT LIMITS, REGULATIONS AND CONTRACTS
Brian Petermann, Area Lead - Air Quality Compliance, POWER Engineers, Inc.

B2.2 MEETING DEMAND WHILE COMPLYING WITH STARTUP AND SHUTDOWN EMISSIONS
Taylor Jones, System Specialist, Environmental Systems Corp (ESC)

B2.3 NH3 SLIP BY EXTRACTIVE METHODS
Matt Swanson, Vice President, Sales, CAI, Inc.

B2.4 STRATIFICATION TESTING - WHEN IS IT REQUIRED?
Dan Todd, President, Air Quality Services, LLC; Paul Siegel and Chris Wehner

B2.5 NEXT-GEN CRDS ANALYZERS FOR MONITORING AMMONIA SLIP IN SCR PROCESSES
Jeremiah Riddle, President, Tiger Optics

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TRACK | B | CEMS & EMISSION TESTING

ROOM 2

Tuesday | 7:30AM - 9:30AM

B3. ESP & PARTICULATE EMISSIONS

B3.1 IMPROVED MEASUREMENT OF LOW PARTICULATE EMISSIONS FROM GAS TURBINES
Kevin Crosby, V.P., Technical, Montrose Air Quality Svcs; Glenn England, Ramboll-Environ

B3.2 THE EFFECT OF 3-PHASE POWER SUPPLY AND SMART CONTROLLER ON ESP
Reza Sharafy, Product Manager, KraftPowercon Sweden AB

B3.3 MORE CASE STUDIES OF THREE PHASE POWER SUPPLIES IMPROVING ESP PERFORMA
John Knapik, ESP Solutions Consultant, Babcock and Wilcox

B3.4 AGING TR SETS ON ELECTROSTATIC PRECIPITATORS - THE HIDDEN LIABILITY
Paul Leanza, Business Development Manager, KraftPowercon

B3.5 A FENCE LINE STUDY OF FUGITIVE EMISSIONS USING THE DV3000
James Matley, Global Sales Executive, Duvas Technologies Ltd.

Tuesday | 10AM - 12PM

B4. PM, CEMS, DUST EMISSIONS

B4.1 COROMAX FOR POWER PLANTS
Mads Kirk Larsen, Global Sales Manager, FLSmidth Airtech

B4.2 NEW GORE LOW DRAG MEMBRANE - REVERSE AIR BAGHOUSE CASE STUDY
John Knotts, Business Development Leader, W.L. Gore and Associates

B4.3 MONITORING LOW LEVEL DUST EMISSIONS & DETECTION OF ABATEMENT FAILURE
Odette Alsen, Regional Manager, envea - Altech Environment U.S.A.

B4.4 DUST EMISSION AND EFFECT OF PM10 & PM2.5 IN URBAN INFRASTRUCTURE
Afrim Syla, Air Quality Specialist, University of Prishtina - Kosovo

B4.5 SAUDI ARAMCO'S SAOO FLARE MINIMIZATION ACHIEVEMENTS
Ahmad Al-Otaibi, Environmental Coordinator, Saudi Aramco; Ensan El-Ayoubi

Tuesday | 1:00PM - 3:00PM

B5. AIR QUALITY MODELING

B5.1 BACKGROUND VS. NEARBY SOURCES - TESTING EPA'S NEW GUIDANCE
Co-Chair - George Schewe, Principal Meteorologist, Trinity Consultants; Brian Otten

B5.2 SOLUTIONS TO NEW U.S. EPA MODELING REGULATIONS
Christopher Occhipinti, Project Professional, NTH Consultants, Ltd.

B5.3 LOW-LEVEL FUGITIVE PARTICULATE EMISSIONS IN AERMOD
Leah Blinn, National Air Practice Lead, APTIM

B5.4 REGIONAL HAZE RULE SECOND DECADAL REVIEW - A BUMPY ROAD AHEAD
Robert Paine, Associate Vice President, AECOM; Jeff Connors

B5.5 DEVELOPMENT OF IMPROVED BUILDING DOWNWASH ALGORITHMS IN AERMOD
Sergio Guerra, Senior Environmental Engineer, CPP, Inc.; Ron Petersen

B5.6 CHARACTERIZING PARTICULATE EMISSIONS FROM EVAPORATION POND MISTERS
Mannie Carpenter, Sr. Engineer, Stantec Consulting Svcs; Amber Summer, Kathy Houed

TRACK | B | CEMS & EMISSION TESTING

ROOM 2

Tuesday | 3:30PM - 5:30PM

B6. MEASUREMENT TECHNOLOGIES

B6.1 SOLVING COMPLIANCE ISSUES USING FTIR MULTIGAS MEASUREMENT TECHNOLOGY
[illegible]

B6.3 AIR QUALITY FORECASTING AND MODELING USING MACHINE LEARING AND IOT
Neil Gerber, Director, New Energy & Environment, IBM

B6.4 PASSING RATA WITH QUANTUM CASCADE/TUNABLE DIODE LASER ANALYZER
David McMillen, Business Development Manager, Emerson

Wednesday | 7:30AM - 9:30AM

B7. ADVANCED TECHNOLOGIES

B7.1 NEW LASER MEASUREMENT TECHNOLOGY
Bernadette Shahin, National Applications Manager, M&C TechGroup North America

B7.3 DSI SAVINGS THROUGH REAL TIME SO3/H2SOV MEASUREMENT
Dan Kietzer, National Product Manager, SICK, Inc.; Chris Psotka

B7.4 PEMS SYSTEM EVOLUTION TO MEET CHANGING POWER PLANT CONDITIONS
Brian Swanson, President, CMC Solutions; Jessica Palmer and Eugene Simon

B7.5 COST EFFECTIVE OPTICAL GAS IMAGING FOR DETECTION OF SF6
Sat Sandhu, Thermography Services Support Manager, Fluke; Justin Sheard

B7.2 TBA
Bruce Herman, ABB Process Analytics

Wednesday | 10AM - 12PM

B8. FENCELINE MONITORING & REMOTE SENSING

B8.1 COMMUNITY-BASED AIR TOXICS FENCELINE MONITORING AND INITIATIVES
Charles Lee, PH.D., CM, Principal Consultant, Trinity Consultants; Steve Walters

B8.2 THE D-FENCELINE MEASUREMENT SYSTEM - ADVANCED REMOTE SENSING SOLUTION
Gilad Shpitzer, CEO, Co-Founder, Atmosfir Optics; Dr. Robert Kagann, Dr. Yael Etzioni

B8.3 OPTICAL REMOTE SENSING FOR FENCE-LINE MONITORING USING QCL
Peter Zemek, SVP - Emerging Tech., Montrose Env. Grp; Daniel Cavicchio,Jr., Block Eng.

B8.4 REAL TIME, LOW LEVEL VOC MONITORING IN STATIONARY AND MOBILE PLATFORMS
LJ Sears, Technical Director, RJ Lee Group

B8.5 WINTERTIME PM 2.5 MOBILE MEASUREMENTS
Randall Baxter, Scientist, Information Technology, T&B Systems; David Bush, David Yoho, Kenneth Underwood

B8.6 LASER DISPERSION SPECTROSCOPY FOR REMOTE SENSING
Mohammed Belal, Business Development Director, MIRICO; Damien Weidmann, Arun Kannath, Johnny Chu

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ADVISORY BOARD

This Track provides current presentations on Advanced Mercury Control technologies and strategies, for compliance with MATS emission limits including Hg, DSI, MATS, ACI, & Amended Silicates.

Monday | 1PM - 3PM

C1. HG MATS COMPLIANCE

C1.1 LOWERING MERCURY COMPLIANCE COSTS THROUGH OPTIMIZATION
Richard MacPherson, President/CEO, ME2C; John Pavlish, Nicholas Lentz, Marcus Sylvester, James Trettell

C1.2 COST SAVINGS ASSOCIATED W/ MATS COMPLIANCE OPERATING AS LOW EMITTING
Brandon Kibler, Project Manager, Novinda Holdings, Inc.; Jeremy Hayes, Black Hills Energy; Clifton Brown and James Butz, Novinda Holdings, Inc.

C1.3 HOW THE RIGHT OPTIMIZATION TEAM CAN IMPROVE YOUR MATS COMPLIANCE STRATEGY
Regina Rodriguez, Chief Operating Officer, Carbonxt; Christine Valcarce, Lindsey Costin, David Mazyck

C1.4 OPTIMIZING ACI COST-PERFORMANCE WITH ADVANCED PAC PRODUCTS
Martin O'Brien, Applications Engineer, Calgon Carbon; Richard Mimna, Jenalle Brewer and Michael Pealer

C1.5 EFFECTIVENESS OF MERCURY CONTROL STRATEGIES: A SURVEY OF MATS IMPLEMENT.
Connie Senior, VP of Technology, ADA-ES, Inc.; Sharon Sjostrom

Monday | 3:30PM - 5:30PM

C2. ACTIVATED CARBON

Reaction Analytics

C2.1 KINETIC CHEMISTRY MODEL FOR MERCURY REMOVAL BY ACI
Guisu Liu, Founder, Reaction Analytics Solutions Corp.

C2.2 HG BEHAVIOR IN HYBRID FILTER WITH INJECTION AND COATING OF AC IN CPP
Jin-Ho Sung, Researcher, Yonsei University; Yong-Chil SEO, Se-Won Park, Ha-Na Jang $ Seung-Ki Back

C2.3 FUTURE OF THE ACTIVATED CARBON INDUSTRY
David Mazyck, Chief Executive Officer, Carbonxt; Curt Larson, Regina Rodriguez, Dennis Baranik

C2.4 OPTIMIZING ACI USAGE TO REDUCE COSTS, AVOID CORROSION, IMPROVE ASH
John Satterfeld, Sr. Field Service Engineer, Cabot Norit Activated Carbon

Tuesday | 7:30AM - 9:30AM

C3. HG CONTROL TECHNOLOGIES

C3.1 AS-ULTRA PERFORMANCE IN THE MOST CHALLENGING CONFIGURATIONS
Thomas Gale, Director of Technology Development, Novinda Holdings, Inc.

C3.2 CIRCULATING DRY SCRUBBER MERCURY CONTROL PRB COAL-FIRED POWER PLANTS
Terence Ake, Principal Engineer, Babcock Power, Inc.; Roderick Beittel

C3.3 INNOVATIVE SORBENT TRAP MEASUREMENT TECHNIQUES: HG, SO3, NH3, HCL, SE
Alexandra Sipershteyn, Product Manager, Ohio Lumex

C3.4 RAPID RESPONSE TESTING TO ENSURE MATS COMPLIANCE
Nicholas Lentz, Field Tech. Manager, Midwest Energy Emissions Corp.; John Pavlish and James Trettel

Tuesday | 10AM - 12PM

C4. DSI & ACI

C4.1 EXPERIENCE WITH RETROFITTING HYDRATED LIME INJECTION SYSTEMS
Jon Norman, Manager - Sales and Technology, United Conveyor Corporation

C4.2 LANCE-LESS DSI TECH ALLOWS CONT. OPERATION OF EXISTING ESPS
Bob Mastropietro, Technical Sales Engineer, Nol-Tec Systems

C4.3 STRATEGIC USE OF TEMPORARY INJECTION SYSTEMS (PAC AND DSI)
Mike Gregory, Business Development - Capital Equipment, IAC

C4.4 SODIUM SORBENTS FOR HIGHER EFFICIENCY
Sponsor & Co-Chair - Michael Atwell, Manager, Solvay Chemicals; Cornelia Cretiu

Tuesday | 1:00PM - 3:00PM

C5. HG CONTROL TECHNOLOGIES

C5.1 USE CHEMISTRY-BASED CFD TO INVESTIGATE DSI OPTIMIZATION OPTIONS
Guisu Lu, Founder, Reaction Analytics Solutions Corp

C5.2 EFFECTIVE AND SIMPLE MERCURY CONTROL IN PLANTS CONFIGURED WITH WET FGD
Thomas Gale, Director of Technology Development, Novinda Holdings, Inc.

Viviron Technology

C5.3 A NOVEL IRON OXIDE-BASED MATERIAL FOR CAPTURING MERCURY VAPOR
Yongheng Huang, Manager, Viviron Technology

C5.4 A SORBENT INJECTION TECHNOLOGY UPDATE
Mitch Lund, Product Manager - Air Pollution Control, Nol-Tec Systems

C5.5 SUSTAINABLE PROCESS FOR POLYPROPYLENE PRODUCTION: A CFD STUDY
Naser Jamshidi, Crisis Management & Passive Defense Manager, National Petrochemical Co.; Reza Marandi

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TRACK | D | POWER GEN & ENERGY SERVICES

ROOM 4

ADVISORY BOARD FOR TRACK D

DTE Energy, Epsilon, Lockheed Martin, Mitsubishi Hitachi Power Systems, Pacific Northwest, Siemens Energy, Solar Turbines, Stantec, TRC, Xcel Energy

This Track includes - Transmission & Distribution; Demand and Rates, Energy Policy, Cyber Security, Power Plant converion Technologies, Distributed Generation, Building Technologies, CHP, & Grid Stability.

Monday | 1PM - 3PM

D1. PLANT PERFORMANCE

D1.1 THE IMPORTANCE OF POWER PLANT PERFORMANCE TESTS
William Stark, Vice President, Environmental Services, Leidos; Michael Giampetro

D1.2 THERE'S MORE THAN JUST A TEST
Mike Hartman, Principal Environmental Specialist, McHale Performance; Dave Price

D1.3 DEAERATOR OPEX AND RELIABILITY UPGRADE & BOILER EMISSION IMPROVEMENT
Rick Nijmeijer, International Sales Manager, Stork Thermeq B.V.

D1.4 MANAGING LOGISTICS FOR SCHEDULED OUTAGES IN POWER & ENERGY
Angela Eliacostas, Founder and President, AGT Global Logistics; Jordan Mock

D1.5 NEW TECHNOLOGY IN-SERVICE API-653 TANK BOTTOM INSPECTIONS USING CERT.
Ron Marsden, General Manager, Manta Robotics; Zach Chapman

Monday | 3:30PM - 5:30PM

D2. POWER PLANT CONVERSION TECHNOLOGIES

D2.1 THE CARBON CHALLENGE FOR THE POWER INDUSTRY
Bruce Rising, Executive Advisor, ADI Analytics, LLC

D2.2 IOT WILL NOT DELIVER ITS POTENTIAL - UNLESS IT SOLVES THIS CHALLENGE
Harry Sim, CEO, Cypress Envirosystems

D2.3 COAL TO GAS CONVERSION ADVANTAGES: CASE STUDY
Joe Brown, Head of Aftermarket Sales, MHPS

D2.4 OPERATING THE EXISTING AQCS SYSTEM AFTER NATURAL GAS CONVERSION
Suzette Puski, Principal Business Dev. Spec., Babcock Power

D2.5 COAL TO GAS CONVERSION: BLACK-END IMPLICATIONS
Karen Whitehead, Mechanical Engineer, Boiler & Air Quality, Black & Veatch Corporation

D2.6 OLD SMOKEY POWER - TRANSFORMING AGING POWER PLANTS
Peter Belmonte, Vice President & Director, Power Generation, TRC

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Tuesday | 7:30AM - 9:30AM

D3. CYBER SECURITY, SAFETY & EFFICIENCY

D3.1 WHAT THE WORLD MUST KNOW URGENTLY ABOUT NUCLEAR SECURITY
Phrantceena Thate-Halres, CEO, Total Tactical Defense

D3.2 SAFETY IN THE ELECTRICITY AND PETROLEUM INDUSTRIES
Fred Mayes, Senior Energy Analyst, U.S. Energy Information Administration

D3.3 CYBER SECURITY FOR POWER: WHERE REGULATION AND REALITY CONVERGE
Mark Rabuano, Manager, NERC Services, NAES Corporation

D3.4 INNOVATION IN ENERGY EFFICIENCY PROGRAM DESIGN
Ian Metzger, Program Development Engineer, Lockheed Martin Energy

D3.5 LOWER GLOBAL WARMING POTENTIAL WITH CO2 HEAT PUMP WATER HEATERS
Cheryn Metzger, Senior Research Engineer, Pacific Northwest National Laboratory

D3.6 PLANNING FOR THE FUTURE: NATION'S FIRST CYBER-SECURE UTILITY MICROGRID
Jim Dodenhoff, Dir. of Business Dev, IPERC

Tuesday | 10AM - 12PM

D4. T&D, GAS TURBINES

D4.1 GAS FUEL FLEXIBILITY FOR GAS TURBINE DISTRIBUTED POWER GENERATION
Michael Welch, Industry Marketing Manager, Siements Industrial Turbomachinery Ltd.

D4.2 FUTURE "ENERGY" UTILITY: DEEP DECARBONIZATION OF ENTIRE ENERGY ECONOMY
Bill Leighty, Founder, The Leighty Foundation

D4.3 WIRELESS POWER TRANSFER SMALL-SCALE PROTOTYPE
Adel El-Shahat, Assistant Professor, Georgia Southern University; Dylan Nelms

D4.4 PREDICTING AND DETECTING GAS TURBINE MALFUNCTIONS
Patrick Bangert, CEO, Algorithmic Technologies, Inc.

D4.5 INNOVATIVE AND INSPIRING GIS TECHNOLOGY FOR PUBLIC WORKS
Matthew McLamb, Chief Technology Officer, Geographic Technologies Gorup, Inc.

D4.6 SITING & PERMITTING FOR TRANSMISSION & DISTRIBUTION
Brian O'Neal, Project Manager, Black & Veatch Corporation

Tuesday | 1:00PM - 3:00PM

D5. ENERGY POLICY, DEMAND AND RATES

D5.1 A TALE OF TWO ISSUES
Stephen Slocomb, Principal, Epsilon Associates

D5.2 ENERGY ECONOMICS AND A SUSTAINABLE ELECTRICITY POLICY
Daniel Mussatti, Senior Energy Economist, US NRC

D5.3 GRID MODERNIZATION POLICY DEVELOPMENTS IN CALIFORNIA
Co-Chair -Larissa Koehler, Senior Attorney, Environmental Defense Fund

D5.4 ONE GOAL, MANY PATHS TO RESILIENCY
Carmen Henrikson, Associate Vice President, TRC Energy Services

D5.5 CURRENT TRENDS AND DEVELOPMENTS FOR ELECTRIC UTILITY RATES
Ted Kelly, Principal & Senior Project Manager, Burns & McDonnell

TRACK | D | POWER GEN & ENERGY SERVICES
ROOM 4

Tuesday | 3:30PM - 5:30PM

D6. BUILDING TECHNOLOGIES

D6.1 ON THE ROAD TO ZERO ENERGY BUILDINGS
Carl Cohen, Project Manager, TRC Energy Services

D6.2 INCENTIVIZING HIGH-PERFORMANCE BUILDING-FINANCING
Teresa Lopez, CEO, Green Energy Money, Inc.

D6.3 SMARTPNEUMATICS - MAKING DUMB BUILDINGS SMART
Harry Sim, CEO, Cypress Envirosystems

D6.4 IMPROVING ENERGY STORAGE PERFORMANCE OF THE CONCRETE CONTAINING FORM-S
Seyed Mojtaba Sadrameli, Professor, Tarbiat Modares University; S. Hasanabadi

D6.5 USING PASSIVE COOLING STRATEGIES TO REDUCE THERMAL COOLING LOAD
Ahmad Zamzam, Architect, Shamayel Development Company

Wednesday | 7:30AM - 9:30AM

D7. CHP

D7.1 COMBINED HEAT AND POWER SOLUTIONS FOR DISTRICT HEATING APPLICATIONS
Dalia El Tawy, Director-Thermal Power Solutions, Siemens

D7.2 ENERGY & AIR POLLUTION REDUCTION FROM COGENERATION AT JOHNS HOPKINS
John Kumm, Senior Engineer, EA Engineering, Science and Technology

D7.3 KILLING TWO BIRDS WITH ONE STONE: 'SMART' COUPLING ENERGY-EFFICIENT CH
Anthony Cirillo, Senior Project Director, AECOM - Power Division

D7.4 MEDIUM VOLTAGE AUXILIARY BOILERS AND FUEL GAS DEWPOINT HEATING SYSTEMS
David Taylor, Director of Technical Sales, Chromalox

D7.5 POWER/WATER SOLUTIONS: USING THERMAL ENERGY FROM CHP PLANTS
Ben Laurent, Senior Process Engineer, Heartland Water Technology, Inc.

Wednesday | 10AM - 12PM

D8. DISTRIBUTED GEN & GRID TECHNOLOGY

D8.1 HYBRID SOLUTIONS PROVIDING GRID STABILITY AND RENEWABLE INTEGRATION
Dalia El Tawy, Director-Thermal Power Solutions, Siemens

D8.2 NATURAL GAS ASSETS TO SUPPORT THE EVOLVING ELECTRIC GRID
Hua Fang, Director, Black & Veatch Management Consulting, LLC

D8.3 WATER-FREE COMBINED CYCLE DISTRIBUTED POWER GENERATION
Michael Welch, Industry Marketing Manager, Siemens Industrial Turbomachinery, Ltd.

D8.4 SMART CIT-HY WINDBUS AUXERRE FRANCE
Emmanuel Schuddinck, CEO, Justy Energies Engineering

D8.5 SIMULATING SOLAR PHOTOVOLTAIC TECHNOLOGY DIFFUSION AND GRID STABILITY
Jacob Monroe, PhD Student, North Carolina State University; Emily Berglund

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ADVISORY BOARD TRACK E

This Track provides current presentations on Advanced technologies and strategies, for compliance with SO2, NOx, CO2 emission limits at coal-fred boilers. Includes SCR, DSI, and measurement and contral in the cement and ash industry.Waste to Energy and Waste management.

TRACK SPONSOR & CO-CHAIRS: (SUBMIT TO INFO@EUEC.COM)

Monday | 1PM - 3PM

E1. CONTROL TECHNOLOGIES

E1.1 NOX CONTROL, AND A LOT MORE, WITH CATALYTIC CERAMIC FILTERS
Rod Gravley, Technology Director, Tri-Mer Corporation; Kayla Olson, Kevin Moss

E1.2 EVALUATION AND APPLICATION OF AN AIR QUALITY MODELING SYSTEM TO ANALYZ
Roberto San Jose, Head Professor, Technical University of Madrid (UPM); Jun L. Pérez, Rosa Maria Gonzalez-Barras

E1.3 ACID GAS REMOVAL CHARACTERISTICS OF CA(OH)2 IN A REAL SITE
Han Jae-Won, Han-Yang University; Young-Ok Park, Korea Institute of Energy Research; Hui-Taek Kim, Han-Yang University

E1.4 FULL-SCALE DEMONSTRATION OF ENZYME-ENHANCED COAL COMBUSTION
Wei-Ping Pan, Professor, Western Kentucky University

E1.5 IT'S ALL IN THE DUST CAKE
Nathan Schindler, Technical Sales Manager, Evonik Corporation; Florin Popovici, Emission Control Engineering Consulting

Monday | 3:30PM - 5:30PM

E2. WASTE TO ENERGY & WASTE MANAGEMENT

E2.1 PLASMA GASIFICATION; THE NEXT GENERATION OF WASTE-TO-ENERGY SERVICES
Richard Fish, President, ALTER NRG CORP.; Kal Bhojak

E2.2 EMISSIONS AND WASTE-TO-ENERGY SYSTEMS
Tina Liu, Atmospherics Specialist, Advisian

E2.3 ELECTRICITY PRODUCTION FROM SRF USING A DOWNDRAFT GASIFICATION PROCESS
Se-Won Park, Researcher, Yonsei University; Lee, Sung, Seo, Yonsei University; Oh, Samho environ-Tech; Gu, Institute for Advanced Engineering

E2.4 WASTED ENERGY FROM COMPRESSED AIR LEAKS: WHAT ONE PILOT PROJECT FOUND
Dan Nickey, Interim Director, Iowa Waste Reduction Center, University of Northern Iowa

E2.5 ENERGY FROM MUNICIPAL SOLID WASTE WITH MINIMAL CARBON EMISSION
Surendra Saxena, Professor Emeritus, FIU; Siva Pillai, Innovision

Tuesday | 7:30AM - 9:30AM

E3. SO2, NOX & SNCR

E3.1 HIGH ACCURACY IN-SITU SO3, SO2 & H2SO4 SENSOR FOR COMBUSTION SOURCES
Bob Finken, Senior Vice President, Montrose Air Quality Services; Dr. Peter Zemek

E3.2 SUCCESSFUL SAMPLE HANDLING SYSTEMS FOR SO2 AND NOX AT SCR
Philipp Zimmel, Area Sales Manager, JCT Analysentechnik GmbH

E3.3 IMPROVE PLANT ECONOMICS WITH EFFICIENT AMMONIA BASED DESULFURIZATION
David Repp, Sales Director, Jiangnan Environmental Technology, Inc.; Jie Li

E3.4 OPERATING CHALLENGES OF EXISTING AIR QUALITY CONTROL SYSTEMS
Suzette Puski, Principal Business Dev. Spec., Babcock Power

E3.5 EXPLORING OXIDATION AND SCR CATALYST ON GAS FIRED UNITS
Emily Kunkel, Senior Environmental Associates, Sargent & Lundy; Raj Giakwad, Dave Helm

Tuesday | 10AM - 12PM

E4. SCR & NOX CONTROL

E4.1 SOFT SENSORS FOR SOX AND NOX EMISSIONS
Patrick Bangert, CEO, algorithmica technologies Inc.

E4.2 COMBINED CYCLE PLANT NOX REDUCTIONS
Jeff Williams, Manager, Emerson; J. Nyenhuis

E4.3 CFD MODELING FOR EVALUATING CONVERSION OF COAL TO GAS FIRED BOILER
Praveen Gonuguntla, Senior CFD Engineer, Tridiagonal Solutions, Inc; Abhay Panwalkar, Bharat Heavy Electricals Limited

E4.4 SELECTABLE CONTROL SYSTEM FOR SCR MANAGEMENT
Bernadette Shahin, National Applications Manager, M&C TechGroup

Tuesday | 1PM - 3PM

E5. WASTE RECYCLING - CEMENT, FLY ASH

E5.1 FASTOX GASIFICATION: PROFITABLY ACIEVE 100% RECYCLING
Michael Kleist, VP of Sales and Marketing, Sierra Energy; Mike Hart

E5.2 ADDRESSING FLY ASH RESISTIVITY WHEN CONTROLLING FLUE GAS ACIDITY
Rabindra Sinha, VP - Sales , Marketing & Technology, ARKAY Technologies

E5.3 CEMENT STABILIZATION OF CONTAMINATED SOIL AND CCR
Paul Ruehl, US Environmental Remediation Coordinator, Lafarge Holcim

E5.4 CONCRETE AND CEMENT SPEC. COAL FLY ASH FROM A WASTE FLY ASH
Christopher Poling, Engineering Director, SCB International Materials

E5.5 CONVERT FOOD WASTE TO ENERGY AND PROFITS
David Blume, CEO, Blume Distillation

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TRACK | E | SO2, NOX & SCR CONTROL

ROOM 5A

Tuesday | 3:30PM - 5:30PM

E6. COMPLIANCE TECHNOLOGIES & STRATEGIES

E6.1 MERCURY AND PYRITIC SULFUR REDUCTION IN CLEANED ILLINOIS BASIN COALS
Allan Kolker, Research Geologist, U.S. Geological Survey, Liliana Lefticariu, Southern Illinois University; Maria Mastalerz, Indiana Geological Survey; Agnieszka Drobniak, Indiana Geological Survey, Clint Scott, U.S. Geological Survey; Anne Scott, U.S. Geological Survey

E6.2 BACT EMISSION LIMITS: THE DEVIL IS IN THE DETAILS
David Shotts, Partner, ERM

E6.3 FUEL ECONOMY AND EMISSIONS TESTING CONDUCTED ON A REEFER TRAILER
Olivia Maier, Chemical Engineer, dynaCERT, Inc.; Robert Maier, Ruston Hoffman

E6.4 ULTRA-LOW TURNDOWN IN AN ULTRA-LOW EMISSIONS WORLD
Meville Hedges, Territory Manager, Cleaver-Brooks, Inc.

SUBMIT ABSTRACT SPEAKING SLOTS AVAILABLE

Wednesday | 7:30AM - 9:30AM

E7. SO2, NOX & SNCR

E7.1 MINIMIZING NOX AND HEAT RATE IN CHINESE COAL FIRED UTILITY BOILERS
Richard Conn, Sr. Director of Technology, Sunco International; Jeff Shan, Sunco International; May Chen, Blue Horizon

E7.2 FAST RAMP HOT SCR'S & UPGRADES TO COMPLY WITH FUTURE NOX BARCT RULES
Robert McGinty, Sr. Product Mgr Gas Turbine & Ind. SCR Sys, Mitsubishi Hitachi Power Sys

E7.3 PRE AND POST COMBUSTION NOX CONTROL SYSTEM USING MICROWAVE TECH.
Valentino Tiangco, Biomass Program Manager, SMUD; Chang Yul Cha, CHA Corporation; Charles Gentry, California Energy Commission

E7.4 HUMIDITY CONTROL OPTIMIZING DRY SCRUBBER OPERATION
Jeff Bossong, COO, H2O LLC, Mark Cantrell, SWEPCO

SUBMIT ABSTRACT SPEAKING SLOTS AVAILABLE

Wednesday | 10 AM - 12 PM

TRACK | F | RE: SOLAR, WIND, FLEX GEN

ROOM 5B

ADVISORY BOARD TRACK F

This Track provides current presentations on Renewable Energy technologies and strategies, including, solar, PV, wind, Nuclear, waste-to-energy, biogas, biomass, biodiesel, financing, and development case studies for peak shaving and FIT programs.

TRACK SPONSORS & CO-CHAIRS: (SUBMIT TO INFO@EUEC.COM)

Monday | 1PM - 3PM

F1. BIOGAS, BIOMASS, BIODIESEL

F1.1 ANAEROBIC HABBR PROCESS FOR HIGH STRENGTH WASTEWATERS
Silvia Angappan, Headworks BIO, Inc.; H. Sonstein Bau

F1.2 TORREFIED BIOMASS SUCCESS AT THE PGE BOARDMAN PLANT
Una Nowling, Service Area Leader, Black & Veatch; Randy Curtis, Portland General Electric Boardman Power Plant

F1.3 INDUSTRIAL SYMBIOSIS THROUGH EFFECTIVE PUBLIC-PRIVATE PARTNERSHIPS
Barry Edwards, Director of Utilities & Engineering, Catawba County

F1.4 DIRECTED BIOGAS SUCCESS AT THE UC SAN DIEGO MICROGRID FUEL CELL
Clark Crawford, Director, Business Development, FuelCell Energy; Robert Nielsen

F1.5 COMPUTATIONAL FLUID DYNAMICS SIMULATIONS OF ALGAE PHOTOBIOREACTORS
Andres Philip Mayol, USAID STRIDE Visiting Scholar, The University of Arizona; Aristotle T. Ubando, Alvin B. Culaba and Joel L. Cuello

Monday | 3:30PM - 5:30PM

F2. FLEX GEN & ONSITE POWER

F2.1 POWER PRODUCTION FOR FUTURE SOLID WASTE RESOURCE RECOVERY FACILITY
Matt Dunn, Principal Engineer, AECOM

F2.2 SOLAR TECHNOLOGY EVOLUTION
Matthias Gewalt, Manager of Solar Practice, Leidos Engineering

F2.3 RECLAIMING CONTAMINATED LAND: DEPLOYING SOLAR ON BROWNFIELDS
Cynthia Christensen, Commercial/Utility Sales Director, Namaste Solar

F2.4 FEDERAL FACILITIES: DEVELOPING & FINANCING ENERGY RESILIENCE
Seth Kirshenberd, Partner, Kutak Rock LLP

F2.5 ELECTRICAL ENERGY MGMT IN HOUSEHOLD REFERIGERATORS AND FREEZERS
Seyed Mojtaba Sadrameli, Professor, Tarbiat Modares Univ., L. Abdollmaleki, A. Pirvaram

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TRACK | F | RE: SOLAR, WIND, FLEX GEN

ROOM 5B

Tuesday | 7:30AM - 9:30AM

F3. RENEWABLE ENERGY & MICROGRID

F3.1 MICROGRIDS AN EFFECTIVE INFRASTRUCTURE ALTERNATIVE
Gregg Edeson, PA Energy Expert, PA Consulting Group; Jared Smith

F3.2 THE ART OF SECURING MICROGRID CONTROL SYSTEMS
Jim Dodenhoff, Dir. of Business Dev, IPERC, Tamer Rousan, Ameren

F3.3 STANFORD'S ENERGY SYSTEM LEADING BY EXAMPLE IN EMISSIONS REDUCTION
Fahmida Ahmed, Director, Sustainability and Business Services, Stanford University

F3.4 NATURAL DISASTERS: A CALL TO ACCELERATE RESILIENCE
Edward Rightor

F3.5 BUILDING ECONOMIC CASES FOR DISTRIBUTED GENERATION & MICROGRIDS
Peter Lilienthal, CEO, HOMER Energy

Tuesday | 10AM - 12PM

F4. RENEWABLE PROJECTS & DEVELOPMENT

F4.1 REDEVELOPMENT OF ELECTRIC UTILITY SITES - INTEGRATING RENEWABLE ENERGY
Steven Putrich, Principal Engineer, Haley & Aldrich

F4.2 EVALUATION OF THE ENVIRONMENTAL IMPACT OF THE THERMAL SPACES
Nasser Alhemiddi, Professor, King Saud Univ.; Abdulrahman Alhemiddi, Abdulaziz Alhemiddi

F4.3 BIRD IN THE HAND: SHOTGUNS, DEADLY OIL PITS, CUTE KITTENS & THE MBTA
Samuel Panarella, Associate Professor of Law, University fo Montana School of Law

F4.4 RENEWABLE ENERGY PROD. AS MEANS FOR LOCAL ECONOMIC DEVELOPMENT
Thobeka Radebe, Researcher, Human Science Research Council

F4.5 THE SHOW MUST GO ON - SOLAR DEVELOPMENT IN WILDLIFE HABITAT
David Lee, Sr. Biologist, Davey Resource Group

F4.6 BIGGER MARKET THAN GRID: RE-SOURCE HYDROGEN TRANSPORTATION FUEL
Bill Leighty, Director, The Leighty Foundation

Tuesday | 1PM - 3PM

F5. WIND ENERGY

F5.1 CONTROL OF A SELF-EXCITED INDUCTION GENERATOR IN A WIND TURBINE SYSTEM
Woonki Na, Assistant Professor, California State University. Fresno; Edurad Muljadi

F5.2 OFFSHORE WIND ENERGY VS CONVENTIONAL IMPLEMENTATIONS
Adel El-Shahat, Assistant Professor, Georgia Southern University; DeAnndra Dixon

F5.3 WIND ENERGY MARKET TRENDS AND CHALLENGES
Nathan Higgerson, Power Generation Project Manager, Hanson Professional Services, Inc.

F5.4 CONVERTING WINDPLANTS TO DEDICATED, OFF-GRID HYDROGEN FUEL PRODUCT
Bill Leighty, Director, The Leighty Foundation

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

TRACK | F | RE: SOLAR, WIND, FLEX GEN

ROOM 5B

Tuesday | 3:30PM - 5:50PM

F6. SOLAR & PV

F6.1 DEMAND CHARGE SAVINGS FROM SOLAR AND ASSOCIATED UTILITY COST SAVINGS
Naïm Darghouth, Sr. Scientifc/Engineering Assoc., Lawrence Berkely Nat'l Lab.; Galen Barbose, Andrew Mills, and Ryan Wiser; Pieter Gagnon and Lori Bird, NREL

F6.2 IMPACT OF DEGRADATION RATES ON SOLAR PV PROJECT FINANCIALS
Matthias Gewalt, Manager of Solar Practice, Leidos Engineering

F6.3 A RESOURCE EVALUATION MODEL FOR A SOLAR VORTEX POWER GENERATION SYSTEM
Amy Moore, Post Doctoral Research Assistant, Oak Ridge National Laboratory

F6.4 ENVIRONMENTAL COMPLIANCE CASE STUDY OF A 100 MWE SOLAR POWER PLANT
Nathan Goodman, VP and Director of Environmental Compliance, The Baldwin Group

F6.5 INDUSTRIAL PRECINCT TRANSITION TO SOLAR
Lio Hebert, PhD Candidate, Curtin University Sustainability Policy Institute

Wednesday | 7:30AM - 9:30AM

F7. HYDRO, GEOTHERMAL, & NUCLEAR

F7.1 WHAT 1,000 GEOTHERMAL HEAT PUMPS WILL DO TO YOUR UTILITY
Will Lange, Director of Sales and utility Marketing, WaterFurnace Renewable Energy

F7.2 BEYOND BASELOAD: NUSCALE DIVERSE ENERGY PLATFORM
Lenka Kollar, Director, Strategy & External Relations, NuScale Power; Chris Colbert

F7.3 GEOTHERMAL ENERGY: SHARING BEST PRACTICES - COMMUNITY ENGAGEMENT
Caitlin Smith, Senior Program Manager, United States Energy Association

F7.4 RENEWGEO - SOLAR AUGMENTED GEOTHERMAL ENERGY
Mark Hauenstein, Managing Partner, UC-Won

F7.5 A MICRO-SCALE HYDRO POWER SYSTEM FOR THE PHILIPPINE INDIGENOUS PEOPLE
Randell Espina,Dean, Ateneo de Davao Univ; Renyl Barroca, Angelito Saluague, Leah Aportadera, Lourdesita Chan

Wednesday | 10AM - 12PM

F8. RENEWABLE ENERGY

F8.1 PV DEGRADATION MITIGATION - A COMMERCIAL PERSPECTIVE
Matthias Gewalt, Manager of Solar Practice, Leidos Engineering

F8.2 GM'S GLOBAL RENEWABLE ENERGY SOURCING BLUE PRINT
Rob Threlkeld, Global Manager - Renewable Energy, General Motors

F8.3 SAN DIEGO STATE UNIVERSITY DEMONSTRATION & PROOF-OF-CONCEPT CENTER
John McMillan, Co-Director SD-REIN, San Diego State University

F8.4 HOW CORPORATE PPAS ARE DRIVING RENEWABLES GROWTH
Scott Nystrom, Director, FTI Consulting; Ken Ditzel

F8.5 PARAMETRIC ANALYSIS FOR COST-OPTIMAL RENEWABLE ENERGY INTEGRATION
Jin Jo, Associate Professor, Illinois State University

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TRACK | G | O&M, DDD, PLANT PERFORMANCE

ROOM 7B

ADVISORY BOARD TRACK G

This Track provides current presentations on current technologies and strategies, for decommissioning of power plants, boiler optimization, project finance, risk management, EMIS, EHS, Health & Safety, operation and maintenance in the electric utility industry.

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Monday | 1PM - 3PM

G1. DECOMMISSIONING OF POWER PLANTS

G1.1 IN-PLACE RETIREMENT OF POWER PLANTS - KEY CONSIDERATIONS AND APPROACH
Co-chair - Jeffery Pope, Decommissioning & Demolition Services Mgr., Burns & McDonnell

G1.2 CLOSURE OF THE D-AREA CCR FACILITIES AT THE SAVANNAH RIVER SITE
Tammy DeRamo, Technical Director, Envirocon; Andrew White and Tripp Winfree

G1.3 SOLVING PCB IMPEDIMENTS TO DECOMMISSIONING
Stephen Mitchell, Senior Vice President, Weston Solutions, Inc.; J.D Groesbeck

G1.4 CHANGES TO PROJECT OBJECTIVES REQUIRES CHANGES TO PROJECT SCOPE
Co-chair - Richard Cheatham, Scientist 5, APTIM; Gene Scott, Ken Beard, Andrew Schaaf

G1.5 KCOM'S RIVERTON, KS EMPIRE DISTRICT ELECTRIC POWER PLANT IMPLOSION.
Joel Spirtas, KCOM Demolition, Commercial / Industrial Demolition and Env. Remediation

G1.6 HOW TO EFFECTIVELY TRANSFER ENVIRONMENTAL LIABILITIES AND POST-CLOSURE
Doug Willett, Executive Vice President, Environmental Liability Transfer, Inc.

Monday | 3:30PM - 5:30PM

G2. O&M COOLING TOWER & POWER PLANT

G2.1 FAILURE POTENTIAL OF RETROFITTED VFD IN COOLING TOWER
Sarah AlKanderi, Research Assistant, Kuwait Institute for Scientific Research, Al-Bassam

G2.2 PERMIAN BASIN ENVIRONMENTAL SUCCESS STORY:REVENUE SHARING WITH VENT G
Jeff Voorhis, Engineer, HY-BON Engineering

G2.3 DISRUPTION IN THE UNDERGROUND: INNOVATIVE UTILITY VAULT REPLACEMENT
Sean Gesell, Manufacturer's Rep, Armorcast Products Company

G2.4 INTEGRATING DEMAND RESPONSE INTO SYSTEM RELIABILITY PLANNING
Paul Grod, President, Rodan Energy Solutions

G2.5 CONNECTICUT UTILITIES TURNKEY SOLUTION TO BENCHMARKING 95% OF THE STATE
Sheri Borrelli, Senior Business Manager, United Illuminating; Samantha Sojka, Eversource Energy

TRACK | G | O&M, DDD, PLANT PERFORMANCE

ROOM 7B

Tuesday | 7:30AM - 9:30AM

G3. OPERATIONS & PLANT PERFORMANCE

G3.1 MITIGATING CLIMATE EFFECTS ON PERFORMANCE OF CCGT-CO2 CAPTURE PLANTS
Hugo Rodriguez, Project Manager, Rengen Energy Solutions; Agustin Alcaraz & Abigail Gonzalez, Instituto Nacional de Electricidad y Energias Limpias

G3.2 INCREASE EFFICIENCY AND REDUCE DOWNTIME WITH DRY ICE CLEANING
David Watson, Director, Business Development - Energy and Services, Cold Jet, LLC

G3.3 SF6 EMISSIONS FROM GAS INSULATED SWITCHGEAR (GIS)
Yasmeen Sultana, Principal, Stantec; Jonya Blahut

G3.4 DRIVING CULTURAL CHANGE-OPERATIONAL EXCELLENCE THRU OVATION SIMULATION
Rob Barden, Technical Training, Platte River Power Authority; Johel Comas

G3.5 POWER GENERATION EXCELLENCE THROUGH DATA-DRIVEN INSIGHT
Mark Scherluebbe, Senior Manager, Ernst & Young; Pat Stiff, WEC Energy Group

Tuersday | 10AM - 12PM

G4. UTILITY DATA MANAGEMENT

G4.1 BETTER MANAGEMENT OF THE COVERSATIONS ABOUT YOUR DATA
David Gloski, President, xOverTime; Michael Lehane

G4.2 CONTINUOUS COMPLIANCE MANAGEMENT FOR UTILITY OPERATIONS
Adam Jackson, Managing Consultant, Trinity Consultants; Colt Sommers, Randall Nelson

G4.3 SPREADING AN EHS CULTURE USING SIMPLIFIED SOFTWARE AND DATA ANALYTICS
John Niemoller, President, Perillon Software

G4.4 HIGH-FREQUENCY DATA COLLECTION AND ENVIRONMENTAL ACCOUNTING
Jeff Ladner, VP Environmental Performance Solutions, Sphera Solutions

G4.5 LEVERAGING TOMORROW'S TECHNOLOGY FOR EHS COMPLIANCE TODAY
James Jensen, Director - Customer Success, Enablon

Tuesday | 1PM - 3PM

G5. PROJECT FINANCE, RISK MGMT

G5.1 HEALTH RISK: KEEPING YOUR POWER PROJECT AFLOAT DURING THE EARLY STAGE
Joseph Sabao, Senior Scientist, Epsilon Associates

G5.2 MANAGING CONTRACTOR CHANGE WITH UPFRONT AND AGREED UPON RATES
Brendan O'Brien, Project Engineer, Burns and McDonnell; Jeff Pope

G5.3 A CAPITAL PROJECT RISK MANAGEMENT APPROACH
Carlos Mendizabal, President, ARETE, Lesli Del Rio

G5.4 INVESTMENT STRATEGIES FOR ENV. MKTS UNDER CURRENT STATE OF NEW REGS
Nedia Miller, Principal, MILLER CTA

G5.5 SAUDI ARAMCO UPSTREAM ENVIRONMENTAL FOCUS – PAST, PRESENT, AND FUTURE
Ensan El-Ayoubi, Southern Area Oil Operations Technical Support Department, Saudi Aramco

G5.6 THE UTILITIES INDUSTRY'S GREATEST CHALLENGE RIGHT NOW = DEMOLITION!
Tim Barker, D4 Program Director, AECOM

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TRACK | G | O&M, DDD, PLANT PERFORMANCE

ROOM 7B

Tuesday | 3:30PM - 5:30PM

G6. OPERATIONS & OPTIMIZATION

G6.1 A THREE YEAR INTERNATIONAL ENERGY CHALLENGE
Steven Driver, Global Energy Manager, Sanofi

G6.2 OPERATIONAL EFFICIENCY GAINS THROUGH GEOSPATIAL TECHNOLOGY ADVANCES
Randy Rhoads, Geospatial Industry Manager, Utilities, Harris Corporation

G6.3 BEST PRACTICES TO REDUCE VENTING AND FLARING WITH ECONOMIC BENEFIT
Jeff Voorhis, Engineer, HY-BON Engineering

G6.4 COMBINED CYCLE CYCLING - OPTIMIZING TGHROUGH BOP IMPROVEMENTS
Kyle Kropf, Engineering Manager, Power Generation Svcs, Black & Veatch Corporation

G6.5 FLUE GAS HUMIDITY MEASUREMENT BENEFITS FOR POWER PLANT APPLICATIONS
Jeff Bossong, COO, H2O LLC

Wednesday | 7:30AM - 9:50AM

G7. HEALTH & SAFETY

G7.1 FIT-FOR-DUTY TESTING IN THE ENERGY INDUSTRY
Richard Bunch, CEO, WorkSaver Systems

G7.2 LAYERING DO'S AND DON'TS FOR ARC FLASH PROTECTION
Derek Sang, Technical Training Manager, Bulwark Protective Apparel

G7.3 SAFE AND EFFICIENT COMBUSTION CONTROL IN GAS-FIRED BOILERS / TURBINES
Barbara Marshik, Power Market Segment Mgr, Servomex; Stephen Firth, Josh Christian

G7.4 CREATING AN OPERATING CULTURE FOR PREDICTABLE, CONSISTENT PERFORMANCE
Peter Bridle, Managing Partner, Pegasus Risk Management

G7.5 EXECUTION MEASUREMENTS TO INCREASE SAFETY PERFORMANCE
David Klocek, Director, Solutions Consulting, Sphera Solutions

Wednesday | 10AM - 12PM

G8. PLANT PERFORMANCE/CHALLENGES

G8.1 OPTIMIZATION OF PLANT PERFORMANCE USING MACHINE LEARNING
Patrick Bangert, CEO, algorithmica technologies Inc.

G8.2 WIND EFFECTS ON AIR-COOLED CONDENSERS: WIND-TUNNEL 2-D FLOW FIELDS
Ryan Parker, Project Engineer, CPP Wind Engineering

G8.3 THE MULTI-SITE HABITAT CONSERVATION PLAN STRATEGY
John Richter, Natural Resources Biologist, Black & Veatch Corporation

G8.4 THE UTILITIES INDUSTRY'S GREATEST CHALLENGE RIGHT NOW - DEMOLITION!
Tim Barker, D4 Program Director, AECOM

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

TRACK | H | ELG, CCR, CCS & FGD

ROOM 8

ADVISORY BOARD TRACK H

This Track provides current presentations on current technologies and strategies concerning CCS, CCR, ELG and coal ash in the electric utility industry.

TRACK SPONSOR & CO-CHAIRS: (SUBMIT TO INFO@EUEC.COM)

Monday | 1PM - 3PM

H1. CCR & ELG COMPLIANCE MGMT.

H1.1 CCR/ELG APPROACHES TO ELG COMPLIANCE
Kyle Crowley, Research Engineer, Southern Company Services

H1.2 DESIGNING A PERFORMANCE TEST PROGRAM FOR A CARBON CAPTURE PROCESS
Rick Krenzke, Project Director, TRC

H1.3 STATES VS FEDS: WHO HAS THE BALL ON WATER AND ASH COMPLIANCE?
Jason Eichenberger, Assoc. Civil Engineer, Burns and McDonnell

H1.4 USE OF SLURRY WALL SYSTEMS TO SUPPORT CCR CLOSURE & CORRECTIVE ACTION
Dale Evans, Senior Director of Technology, Remedial Construction Services; Kate Whysner

H1.5 MASS DISCHARGE METRICS TO SUPPORT REMEDY SELECTION AT COAL ASH SITES
Stephanie Jones, Environmental Engineer, Geosyntec Consultants

Monday | 3:30PM - 5:30PM

H2. COAL ASH, CCR & FGD

H2.1 GEOCHEMICAL ANALYSIS OF COAL ASH CONSTITUENTS IN DRINKING WATER
Paula Panzino, Technical Expert, Haley & Aldrich, Inc.; Jacob Chu, Lisa Bradley

H2.2 RULES SHIFT AMERICA'S RESOURCE ABUNDANCE TO SHORTFALL
Danny Gray, Executive Vice President, Charah, LLC

H2.3 HOW DENSE SLURRY TECHNOLOGY CAN HELP ACHIEVE ZERO LIQUID DISCHARGE
Dale Timmons, Program Manager, NAES Corporation

H2.4 REQUALIFYING FLY ASH FOR BENEFICIAL USE/SALE USING AMENDED SILICATES
Steve Baloga, P.E., VP Engineering and Environmental Services, Novinda Holdings, Inc.

H2.5 SELENIUM: HOW SULFUR'S LITTLE BROTHER COULD AFFECT WASTEWATER TREATMENT
Nick Nelson, Vice President, Barr Engineering

H2.6 RECLAIMING AND RECYCLING COAL COMBUSTION RESIDUALS FOR BENEFICIAL USE
Bill Fedorka, Executive Director, Advanced Technology and Projects, SEFA

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Tuesday | 7:30AM - 9:30AM

H3. CCR RULE

H3.1 GROUNDWATER MONITORING AT CCR FACILITIES: NEXT STEPS
Tammy Rauen, Senior Engineer, Golder Associates; Craig Schuettpelz, Todd Stong

H3.2 CCR DATA MANAGEMENT: TOOLS TO AUTOMATE DATA COLLECTION & ANALYSIS
Christine Lew, Manager, Environ. Software/Data Mgmnt Svcs, Tetra Tech, Michael Ungs

H3.3 CCR RULE LOCATION RESTRICTION FUNDAMENTALS & STRATEGIES
Eric Nelson, Vice President, Senior Project Manager, SCS Engineers

H3.4 SITING & DESIGN OF NEW UWLS AND GWM SYSTEMS PURSUANT TO THE CCR RULE
Gary Pendergrass, Principal Geological Engineer & Environmental Group Leader, GeoEngineers, Inc.

H3.5 HONEY I SHRUNK THE POND: CONSIDERATIONS FOR TANK BASED LOW VOLUME WWT
Dave Guinta, Chemical Engineer,Burns & McDonnell; Jared Troyer, Duke Energy

H3.6 IMPLICATIONS AND STRATEGIES FOR THE CCR RULE LOCATION RESTRICTIONS
Thomas Dehlin, Senior Engineer, Fossil Power Tech., Sargent & Lundy; David Nielson

Tuesday | 10AM - 12PM

H4. CCR & ELG

H4.1 CCR INDUSTRY - BENCHMARKING THE INDUSTRY TO PREPARE FOR CHANGE
Mark Rokoff, Vice President, AECOM

H4.2 EVALUATION OF CCR GROUNDWATER MANAGEMENT STRATEGIES
John Hesemann, Regional Envionmental Practice Mgr, Burns & McDonnell; Wayne Weber

H4.3 LESSONS LEARNED FROM ELG COMPLIANCE PROJECTS
Kevin McDonough, Vice President of Sales and Marketing, United Conveyor Corporation

H4.4ENGINEERED IMPOUNDMENTS TO MANAGE CCRS AND LOW VOLUME WASTEWATER
Craig Schuettpelz, Senior Project Engineer, Golder Associates, Ryan Shedivy, Todd Stong, Golder Associates; Jennifer Charles, Great River Energy

H4.5 OPERATE LIKE THERE IS NO TOMORROW WITH CCR UNIT CLOSURES IN MIND
Jason Pokorny, Senior Project Manager, Haley & Aldrich

H4.6 A DETAILED OVERVIEW OF THE KLEENWATER PILOT SYSTEM FOR ELG COMPLIANCE
Mark Pastore, VP Technology, KLeeNwater

Tuesday | 1PM - 3PM

H5. COAL ASH, CCR & CCP

H5.1 PURSUING 100% CCP BENEFICIAL USE... AND BEYOND
Neal Kochis, Senior Project Manager, Haley & Aldrich

H5.2 CCR LANDFILL CHALLENGES FROM SITING THROUGH CONSTRUCTION
Gabe Lang, Program Manager,Senior Engineer, AECOM; Dave Skeggs, Rachel Combs

H5.3 PROTECTING THE "CLOSED LOOP" IN WET BOTTOM ASH SYSTEMS
Paul Pigeon, Associate, Golder Associates

H5.4 RESEARCH ON DECARBONIZATION OF FLY ASH BY TRIBOELECTRIC SEPARATOR
Youjun Tao, Professor, China University of Mining & Technology; Ling Zhang, Zhang Weichi, Xue Yawen

H5.5 A CLOSURE IN-PLACE SUCCESS, WHILE FACILITATING FUTURE SOLAR FACILITY
Jason Fifarek, Senior Associate, Sargent & Lundy; David Jolivet, Sargent & Lundy; William Skalitzky, Jeffery Maxted, Alliant Energy

H5.6 MICROWAVE-ASSISTED RECOVERY OF REES FROM COAL COMBUSTION PRODUCTS
Megan Macala, Research Scientist, AECOM; Elliot Roth, AECOM; Tracy Bank, AECOM; Phillip Tinker, AECOM; Bret Howard, U.S. Dept. of Energy NETL; Evan Granite, U.S. Dept. of Energy NETL

TRACK | H | ELG, CCR, CCS & FGD
ROOM 8

Tuesday | 3:30PM - 5:50PM

H6. FGD, ELG & CCR

H6.1 ADVANCED MATERIALS FOR ELG COMPLIANCE WASTEWATER TREATMENT
Charles McCosey, Industrial Vertical Business Manager, evoqua Water Technologies

H6.2 BOTTOM ASH OPTIONS FOR ELG AND CCR COMPLIANCE
Gerald Long, Manager, North America, United Conveyor Corporation

H6.3 RESPONSIBLE MANAGEMENT OF FGD BYPRODUCTS
Keith Ambrose, Chemical Engineer, Duke Energy

H6.4 OPTIMIZING FGD SYSTEMS FOR MERCURY CONTROL AND ELG WASTEWATER
Katherine Dombrowski, Tech. Development Department Manager, AECOM, Gary Blythe

H6.5 AN INNOVATIVE FINAL CLOSURE AND REVETMENT TECHNOLOGY FOR CCR
Paul O'Malley, Vice President, Sales, Watershed Geo

Wednesday | 7:30AM - 9:30AM

H7. CCS

H7.1 POLICY PARITY FOR CARBON CAPTURE
Heather Greenley, Program Coordinator, USEA

H7.2 THE U.S. DEPARTMENT OF ENERGY'S MAJOR CCS DEMONSTRATION PROJECTS
Thomas Sarkus, Industrial Partnerships Manager, National Energy Technology Laboratory

H7.3 A METHOD FOR PREDICTING CCR LANDFILL LEACHATE GENERATION VOLUME
Cedric Ruhl, Senior Engineer, Wood Group PLC.

H7.4 FTIR MONITORING SYSTEM PROVIDES TIGHTER CONTROL ON EMISSIONS FROM C
Co-Chair - Jim Cornish, Sales & Support Manager, Gasmet Technologies

H7.5 INNOVATIVE METHODOLOGIES FOR ASSESSMENT, IDENTIFICATION & MITIGATION
Hari Gupta, Director, Coriolis Enterprises

H7.6 IMPROVED ECONOMICS FOR CARBON CAPTURE RETROFITS AT EXISTING PC PLANTS
Robert James, General Engineer, US DOE NETL; Eric Grol, Jeff Hoffmann, Travis Shultz, US DOE NETL; Eric Lewis, Leidos

Wednesday | 10AM - 12PM

H8. RARE EARTH ELEMENTS

H8.1 RECOVERY OF RARE EARTH METALS FROM COAL COMBUSTION RESIDUALS
Joseph Laurino, President, Periodic Products, Inc.; Zachary Huba

H8.2 TEA OF BIOLOGICAL PROCESS FOR REE RECOVERY FROM END-OF-LIFE MATERIALS
David Reed, Research Scientist, Idaho National Laboratory; Y. Jiao, D. Park, A. Brewer, S. Singer, W. Bourcier LLNL, V. Thompson, Y. Fujita, M. Crain-Zamora, M. Yim, M. Jindra, V. Nguyen, INL; H. Jin, M. Gupta, J. Sutherland, Purdue; L. Ho, BioReactor Sci, S. Woods, NTEC; L. Lammers, UC Berkeley

H8.3 RARE EARTH ELEMENTS IN COAL AND COAL COMBUSTION PRODUCTS
Elliot Roth, Research Engineer, NETL/AECOM; Megan Macala, AECOM/NETL; Ronghong Lin, ORISE; Tracy Bank, AECOM/NETL; Bret Howard, NETL; Evan Granite, NETL; Yee Soong, NETL

H8.4 DETERMINATION OF RARE EARTHS IN COAL COMBUSTION BY-PRODUCTS
Evan Granite, Research Chemical Engineer, USDOE / NETL; Elliot Roth -NETL, Tracy Bank - NETL, Mary Anne Alvin - NETL, Ken Ladwig - EPRI

H8.5 RECOVERY OF RARE EARTH ELEMENTS FROM NORTH DAKOTA LIGNITE COAL
Daniel Laudal, Manager-Major Projects, Inst. for Energy Studies, University of North Dakota; Steven Benson, Microbean Tech. Inc., Dan Palo, Barr Eng., R. Shane Addleman, PNNL

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TRACK | I | WATER & 316(b)

ROOM 9

ADVISORY BOARD TRACK I

This Track provides current presentations on current technologies and strategies, concerning water and wastewater management, including 316 (b), cooling towers, FGD, ZLD, coal ash, and remediation in the electric utility industry.

TRACK SPONSOR & CO-CHAIRS: (SUBMIT TO INFO@EUEC.COM)

Monday | 1PM - 3PM

I1. WASTEWATER MANAGEMENT

I1.1 PARTNERING WITH BIG INDUSTRY TO REDUCE NUTRIENT POLLUTION
Sarah Gilstrap, Senior Environmental Scientist, Burns & McDonnell Engineering Company

I1.2 CCR WATER SAMPLING AND ANALYSIS DATA QUALITY ISSUES
David Thal, Principal Chemist, Environmental Standards, Inc.; Vitale, Gable, Dicken, Martin

I1.3 A PROMISING ASH POND WATER TREATMENT METHOD UTILIZING FLYASH
Lisa Andrews, Environmental Engineer and Tom Radue, Vice President, Barr Engineering; Jeong-Yun Won, Barr Engineering; Maggie Skelton, Minnesota Power

I1.4 EFFECTIVE CLARIFICATION TO MEET TIGHT TRACE METAL LIMITS
Dennis Fink, Water for Power Lead, Jacobs; Thomas E. Higgins and Mary McCloud

I1.5 THERMAL EVAPORATIVE WASTEWATER TREATMENT: SCALE CONTROL & MGMT
Todd Whiting, Sr. VP Power Generation Operations, Purestream Services

Monday | 3:30PM - 5:30PM

I2. WATER TREATMENT & FLOOD MITIGATION

I2.1 A PARADIGM SHIFT IN WATER TREATMENT
Aaron Morrison, President & CEO, Chaoticwaters, Inc.

I2.2 WATER UNDER THE BRIDGE - DETECTION & CONTAINMENT OF LEAKS & SPILLS
Chris Chase, Environmental Systems Manager, InterOcean Systems, LLC; Seung C. Lee, Shinhan Technologies Co., Ltd.

I2.3 ALTERNATE SOURCE DEMONSTRATION USING MULTIVARIATE STATISTICS
Natasha Hausmann, Senior Scientist, ERM; Brian Bjorklund

I2.4 CAPACITIVE DEIONIZATION OF A METAL-CONTAMINATED UNDERGROUND WATER
H. Paul Wang, Professor, National Cheng Kung University, Chong, Nat'l Cheng Kung Univ; J. Wang, Univ. of Cal, San Diego; Wei, Tunghai University, Lin, National Tsing-Hua University

I2.5 FLOOD MITIGATION MEASURES - WHEN, WHERE, AND HOW
Jeff Roushey, Senior Product Engineer, ILC Dover LP; Steve Brady

I2.6 NEW YORK UNIVERSITY COMMITMENT AND INITIATIVES FOR SUSTAINABILITY
Bapanaiah Penugonda, Associate Professor/Group Practice Director, New York University Dentistry; P. Buccigrossi, D. Jung-Hyun, K. Baron

TRACK | I | WATER & 316(b)

ROOM 9

Tuesday | 7:30AM - 9:30AM

I3. 316(b)

I3.1 INTER-YEAR VARIABILITY IN IMPINGEMENT AND ENTRAINMENT RATES
Greg Seegert, Chief Ichthyologist, EA Eng.; J. Rager & J. Vondruska, EA; D. Dixon, EPRI

I3.2 PEER REVIEWER IDENTIFICATION, SELECTION AND MANAGEMENT
Christopher Wiggins, Sr. Aquatic Scientist, Burns & McDonnell

I3.3 USE OF CFD TO OPTIMIZATION A FISH RETURN DISCHARGE LOCATION
Nathaniel Olken, Principal Engineer, Alden Research Laboratory

I3.4 A CONSORTIUM APPROACH TO 316(B) FOR FACILITIES ON THE MISSISSIPPI RIVER
Kurtis Schlicht, Technical Director, Environmental Resources Management

I3.5 GREEN ALTERNATIVES FOR WATER SUPPLY DEVELOPMENT
Henry Hunt, Sr. Project Manager, Layne-Ranney

I3.6 CASE STUDY OF RETROFITTING THE DAIRYLAND MADGETT PLANT INTAKE
Brett DeRousse, National Account Manager, Hydrolox; Mike McCullick; Dairyland Power

Tuesday | 10AM - 12PM

I4. FGD WASTEWATER & ZLD

I4.1 INNOVATIVE FGD WASTEWATER TREATMENT ADN ZLD OPTIONS
Malcolm Man, Executive Vice President, Saltworks Technologies, Inc.; Ben Sparrow

I4.2 ADVANTAGES OF ZLD COMPLIANT DENSE SLURRY ASH DISPOSAL SYSTEMS (DSS)
Tobias Lutz, Product Manager, Putzmeister Solid Pumps GmbH; Uli Freitag

I4.3 ENTRAINMENT STUDIES AT THE ALLIANT EDGEWATER GENERATING STATION ON LAK
Christopher Wiggins, Sr. Aquatic Scientist, Burns & McDonnell

I4.4 USING BRINE ENCAPSULATION TECH. TO MANAGE POWER PLANT WASTEWATER
Clark Harrison, Director of Business Development, Purestream Services; Todd Whiting

I4.5 WATER REUSE - ZERO LIQUID DISCHARGE IN A COMBINED CYCLE PLANT
Kenneth Chen, Process Specialty Engineer, Fluor Enterprises; Americus Mitchell, Joe Guida

I4.6 COMBINED BRINE CONCENTRATION - SOLIDIFICATION FGD BLOWDOWN TREATMENT
Lanny Weimer, Market Development Manager, Global Product Manager, Suez

Tuesday | 1PM - 3PM

I5. FGD WASTEWATER & ELG

I5.1 INVESTIGATING OPTIONS FOR CLOSING THE BOTTOM ASH LOOP
Krystal Perez, Industrial Water-Power Practice Lead, Jacobs

I5.2 FO TECHNOLOGY FOR FGD WASTEWATER PRODUCES ELG COMPLIANT STREAM
Margarita Luis, Vice President - Inside Sales, Fluid Technology Solutions, Inc.; Fabian Solberg; Eisenmann

I5.3 NANO-FILTRATION TREATMENT OF FGD WATER TO MEET ELG STANDARDS
Jonathan Chen, Process Engineer, BKT

I5.4 FGD WASTEWATER TREATMENT
Mike Preston, Industrial Water Treatment Section Leader, Black & Veatch

I5.5 INTEGRATED APPROACH TO PLANT WATER AND ELG
Jim Dougherty, President - Environmental, Babcock Power

I5.6 CUSTOM FIBERGLASS REINFORCED PLASTIC PIPING APPLICATIONS IN WET FGD SLURRY AND WASTEWATER PROCESSING
Kira Kaleps, Sales & Business Development Manager, RPS Composites

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TRACK | I | WATER & 316(b) COOLING TOWER

ROOM 9

Tuesday | 3:30PM - 5:30PM

I6. 316(b), ELG, WASTEWATER

I6.1 LOW VOLUME WASTEWATERS: COLLECTING DATA FOR CRITICAL DECISIONS
Karen Burchardt, Associate Environ. Engineer, Burns and McDonnell, Douglas Randall

I6.2 REAL TIME ORGANIC DISCHARGE CONTROL FOR FGD WASTEWATER
Amanda Scott, Industrial & Environmental Manager, Suez Water Technologies

I6.3 ONLINE MULTI-METALS WATER ANALYZER FIELD DEMONSTRATION
Troy Pittenger, R&D Director, Cooper Environmental Services; Brian Edge

I6.4 PILOTING FOR SUCCESS
Krystal Perez, Industrial Water-Power Practice Lead, Jacobs; Tim Harrison, Heyward Subar; Jeffrey Tudini

I6.5 SECTION 316(A) COMPLIANCE ON LARGE FRESHWATER RIVERS
Christopher Wiggins, Sr. Aquatic Scientist, Burns and McDonnell

I6.6 LARGE DIAMETER FRP EQUIPMENT FOR CORROSION RESISTANT SERVICE
Tom Rhone, Regional Sales Manager, Ershigs, Inc., Denali Companies

Wednesday | 7:30AM - 9:30AM

I7. 316(b), COOLING & WASTEWATER

I7.1 ONLINE SELENIUM SPECIATION ANALYSIS TO AID ELG COMPLIANCE PROGRAMS
Vladimir Dozortsev P.h.D., Development Manager, Aqua Metrology Systems Ltd.

I7.2 EFFECTS OF COOLING WATER INTAKES ON FEDERALLY LISTED SPECIES
Brandon Johnson, Sr. Project Manager, Stantec

I7.3 PHOTODEGRADATION OF IBUPROFEN BY G-C3N4/BI2WO6/RGO UNDER VISIBLE LIGHT
Shou-Heng Liu, Professor, National Cheng Kung University

I7.4 APPLICATION OF DEMULSIFICATION METHOD FOR TREATMENT OF OILY WATER
Karim Ghasemipanah, Group Manager of Water and Wastewater Treatment Research, Research Institute of Petroleum Industry; Sadegh Shokouhi, Kimia Saba Sahand Shahraz

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

Wednesday | 10AM - 12PM

I8. WATER SUPPLY & SECURITY

I8.1 SPECIAL TOXICOLOGICAL CONSIDERATIONS FOR CCR CONSTITUENTS
Lisa Bradley, Principal Toxicologist, Haley & Aldrich

I8.2 IT'S NOT JUST WATER – THE SCIENCE AND IMPORTANCE BEHIND COLLECTING REP
Michael McMenus, Sr. Process Specialist, Kiewit Engineering

I8.3 RESILIENCE & ADAPTATION: EVALUATING RISKS TO THE YUKON RIVER WATERSHED
Lawrence Duffy, Professor, University of Alaska Fairbanks; KL Dunlap, BH Dainowski

I8.4 ENERGY EFFICIENCY IN WATER/WASTEWATER SYSTEMS
Guru Navaneetham, Engineering Supervisor, Lincus, Inc.; Sabarish Vinod and Jorj Nofal

I8.5 ASSESSMENT OF HEAVY METALS POLLUTION OF SOME WATER RESOURCES
Abdrabelnabi Abdelhady, Professor, Damanhour University

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

TRACK | J | BATTERY & ENERGY STORAGE

ROOM 10

ADVISORY BOARD

This Track provides current presentations on current technologies and strategies, concerning energy storage, batteries, charging, EV, and PHEV

TRACK SPONSOR & CO-CHAIRS: (SUBMIT TO INFO@EUEC.COM)

Monday | 1PM - 3PM

J1. EV CHARGING HYBRID & FLEETS

J1.1 HYBRIDIZATION OF COMMUTER PASSENGER RAIL
Dave Cook, CTO, Rail Propulsion Systems

J1.2 ELECTRIFYING FLEETS: CAN IT BE DONE?
Glenn Carver, VP of Sales, Green4U Technologies, Inc.; Tim Echols, State of Georgia

J1.3 LARGE BATTERY ENERGY STORAGE: STATIONARY AND V2G
Paul Scott, VP - Advanced Technologies, TransPower; Joshua Goldman

J1.4 MODELING ENERGY-SAVING FREIGHT DELIVERY SCENARIOS
Amy Moore, Postdoctoral Research Associate, Oak Ridge National Laboratory

J1.5 EV TO GRID INTEGRATION - HOW IT WORKS. WHY IT MATTERS.
Preston Roper, Chief Marketing & Operating Officer, eMotorWerks

J1.6 DRIVE ON SUNSHINE WITH ENVISION SOLAR'S EV ARC
Lucia Asbury, Marketing Manager, Envision Solar

Monday | 3:30PM - 5:30PM

J2. BATTERY & ENERGY STORAGE

J2.1 HEAVY RAIL WAYSIDE ENERGY STORAGE SYSTEMS FOR PASSENGER AND FREIGHT
Brian Yanity, Research Engineer, Rail Propulsion Systems

J2.2 ELIMINATING THE HARM OF BUNDLED-COST OR BUNDLED-BENEFIT CAR PARKING
Michael Bullock, Transportation Advisor, Evolved Wireless, Inc.

J2.3 ENERGY STORAGE & MGMT FOR TRANSPORTATION & STATIONARY ENERGY USE (INVITED)
Andrew Frank, CTO, Efficient Drivetrains Inc.

J2.4 LITHIUM ION BATTERY SAFETY MONITORING
Steve Cummings, Sr. Applications Engineer, Nexceris; Nick Frank, Scott Swartz, William Dawson

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

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TRACK | J | BATTERY & ENERGY STORAGE

ROOM 10

Tuesday | 7:30AM - 9:30AM

J3. ENERGY STORAGE SYSTEMS

J3.1 IMPLICATIONS DUE TO THE ABSENCE OF USE CASE TESTING STANDARDS
Cory Stonebraker, Senior Consultant, Leidos Engineering

J3.2 THE VALUE OF OPTIONALITY IN DEPLOYING GRID STORAGE
Jeremy Dockter, Co-Founder and Managing Partner, Expansion Energy LLC; David Vandor, Expansion Energy; David Beck, Audubon Engineering; Gene Larson, SNC-Lavalin Constructors

J3.3 HIGH-EFFICIENCY LAES+COMBINED CYCLE GENERATION TECHNOLOGY: VPS CYCLE
Jeremy Dockter, Co-Founder and Managing Partner, Expansion Energy LLC; David Vandor, Expansion Energy; David Beck, Audubon Engineering; Gene Larson, SNC-Lavalin Constructors

J3.4 RECENT ENERGY STORAGE PROJECTS COMPLETED AT SOUTHERN CALIF. EDISON
Vibhu Kaushik, Director of Grid Technology & Modernization, Southern California Edison

J3.5 TBD
John H. Holmes, Industry Alliance Officer, University of California San Diego

Tuesday | 10AM - 12PM

J4. BATTERY PACK DSM GRID & STORAGE

J4.1 SOLAR + STORAGE: IF YOU CAN MAKE IT HERE, YOU CAN MAKE IT ANYWHERE
Ronald Spalter, Deputy Chief Operating Officer, City University of New York

J4.2 CHALLENGES IN LIB MATERIAL DEVELOPMENT FOR ENERGY STORAGE APPLICATIONS
Dee Strand, Chief Scientific Officer, Wildcat Discovery Technologies

J4.3 BATTERY PACK - DEMAND SIDE MANAGEMENT PROGRAM (INVITED)
Jimmy Kim, CEO, SolarBox®, Irvine, Ca

J4.4 GRID SCALE ENERGY STORAGE PROSPECTS AT ISO/RTO (INVITED)
Rao Konidena, Principal Advisor, Midcontinent ISO

J4.5 TESLA POWER WALL (INVITED)
TESLA

Tuesday | 1PM - 3PM

J5. EV, STORAGE & ONSITE POWER

J5.1 MODULAR LNG :ALTERNATIVE BACK-UP ENERGY SUPPLY FOR POWER GENERATORS (INVITED)
Michael Nicoloro, Senior Vice President, Sanborn, Head & Associates; Joan Fontaine

J5.2 MAINTAINING SYSTEM VOLTAGE WITH BATTERY STORAGE
Craig Dalziel, Director, GP Strategies; Gary Tindall, AES Corporation

J5.3 WORKING TOGETHER TO BUILD EV-READY CONNECTED COMMUNITIES
Russell Vare, Manager, Business Development, Mercedes-Benz Energy

SUBMIT ABSTRACT **SPEAKING SLOTS AVAILABLE**

TRACK | J | BATTERY & ENERGY STORAGE

ROOM 10

Tuesday | 3:30PM - 5:30PM

J6. ENERGY STORAGE TECHNOLOGIES

J6.1 ENERGY STORAGE < $ 1.00 / KWH CAPEX: HYDROGEN & AMMONIA FUELS
Co-Chair - Bill Leighty, Director, The Leighty Foundation

J6.2 ENERGY STORAGE AT GROUNDWATER BANKS
Mark Beuhler, General Manager, Willow Springs Water Bank; Lon W. House, Water and Energy Consulting

J6.3 HYDROGEN AS ENERGY STORAGE MEDIUM AND FUEL FOR SIGT
Joshua Partheepan, Assistant Professor, West Texas A&M University, Emily Hunt

J6.4 ECONOMIC DISPATCH OF LIQUID AIR POWER & STORAGE
William Conlon, President, Pintail Power LLC;

J6.5 LIFE AND SAFETY OF LITHIUM-ION
Taylor Kelly, Director of Energy Storage, Intertek

Wednesday | 7:30AM - 9:30AM

J7. BATTERY & STORAGE SYSTEMS

J7.1 OPERATIONAL CHANGES ON LIFE AND PERFORMANCE
Taylor Kelly, Director of Energy Storage, Intertek

J7.2 MODELING AND EVALUATING HYBRID SOLAR-HYDROGEN FUEL CELLS
Ehsan Kamel, Assistant Professor, New York Institute of Technology; Nicolas Vizcaino

J7.3 DEPLOYMENT OF EOS' ZNYTH BATTERY & REAPING ECONOMIC BENEFITS IN CA
Philippe Bouchard, SVP, Business Development & Marketing, Eos Energy Storage

J7.4 ENABLING LARGE-SCALE RENEWABLES IN THE WESTERN U.S.
Robert Schulte, Principal, Schulte Associates; Fredric Fletcher

Wednesday | 10AM - 12PM

J8. ENERGY STORAGE

J8.1 FUELING THE ENERGY STORAGE REVOLUTION (INVITED)
Andrew Miller, Analyst, Benchmark Mineral Intelligence

J8.2 ENERGY GENERATION AND STORAGE USING FLOATING PV PLANT ON LAKE MEAD
Ehsan Kamel, Assistant Professor, New York Institute of Technology; Peter Baron

J8.3 TRUE LONG DURATION ENERGY STORAGE
Matthew Barnett, Business Development Director, Highview Power

J8.4 C-FREE HYDROGEN FUEL EFFICIENCY STORED AND DELIVERED FOR TRANSPORT
Bill Leighty, Director, The Leighty Foundation; Jack Swearengen, David White, Matthew Kern, WindToGreen, LLC

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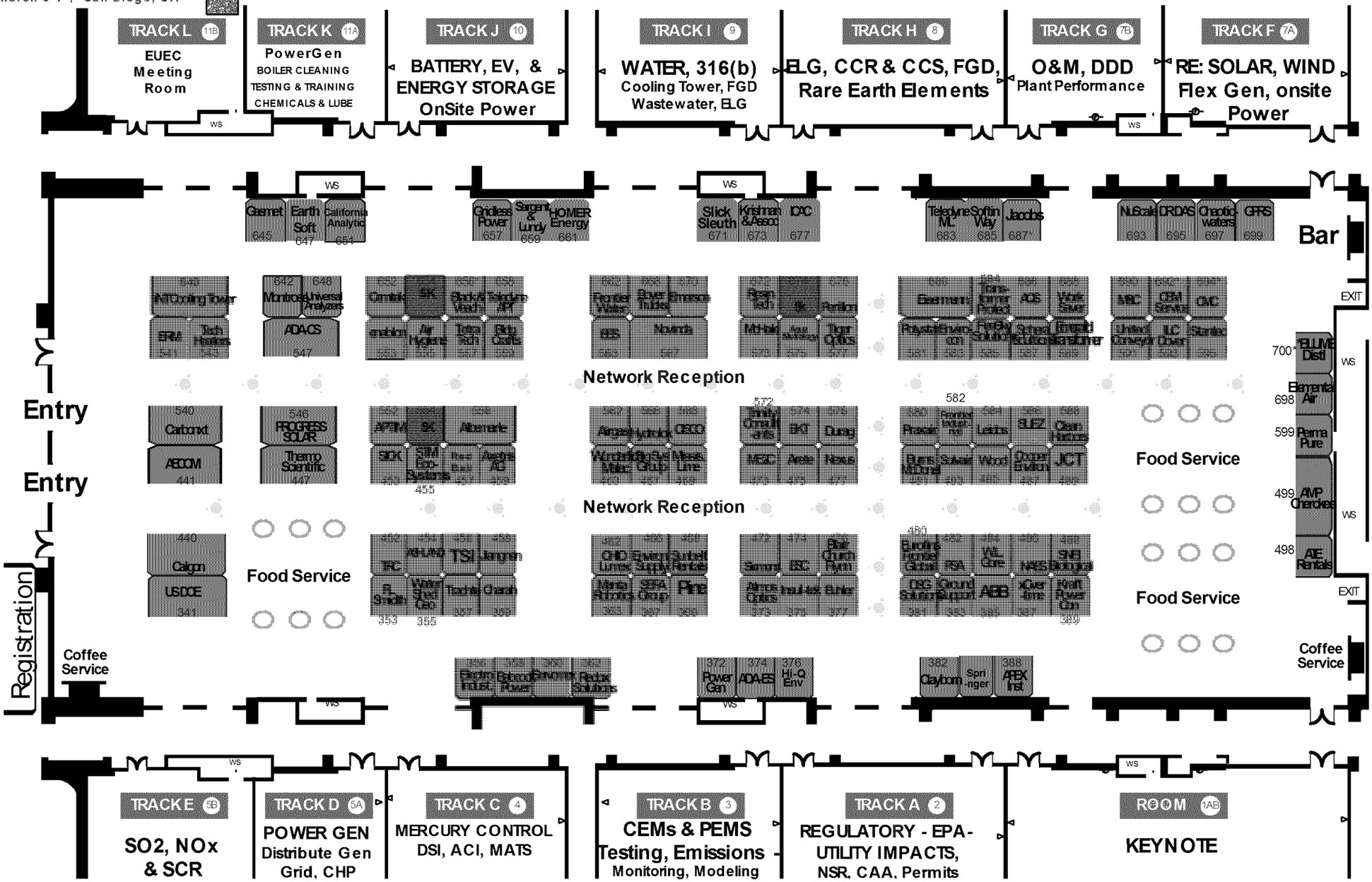

TRACK E 5B
SO2, NOx & SCR

TRACK D 5A
POWER GEN
Distribute Gen Grid, CHP

TRACK C 4
MERCURY CONTROL
DSI, ACI, MATS

TRACK B 3
CEMs & PEMS
Testing, Emissions - Monitoring, Modeling

TRACK A 2
REGULATORY - EPA - UTILITY IMPACTS,
NSR, CAA, Permits

ROOM 1AB
KEYNOTE

EXHIBIT BOOTH & SPEAKER PACKAGE ($5,000)

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5. Pre and post conference attendee list
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EXHIBIT SHOW HOURS
Sun. Setup 12 pm to 6 pm

NETWORK RECEPTIONS
located in Exhibit Hall
AM Breaks 9:30 am to 10 am

Not to Scale

Booth Number - Exhibiting Companies

385 ABB, Inc.
547 ADA Carbon Solutions
374 ADA-ES
498 Advanced Test Equipment
441 AECOM, Inc.
555 Air Hygiene
686 Air Quality Services
562 Airgas
556 Albemarle
499 AMP Cherokee
388 Apex Instruments
552 APTIM
575 Aqua Metrology Systems
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559 Building Crafts, Inc
481 Burns & McDonnell
440 Calgon Carbon
651 California Analytical Corp.
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553 Enablon
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563 Environ. Energy Svcs. (EES)
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383 Ground Support
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640 Int'l Cooling Tower (ICT)
687 Jacobs
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458 Jiangnan Environmental
389 Kraft Power Con
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584 Leidos
690 M & C Tech Group NA
363 Manta Robotics, LLC
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469 Mississippi Lime Company
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369 Pine
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362 Redox Solutions
672 Resin Tech
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360 Servomex
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472 Siemens Industry, Inc.
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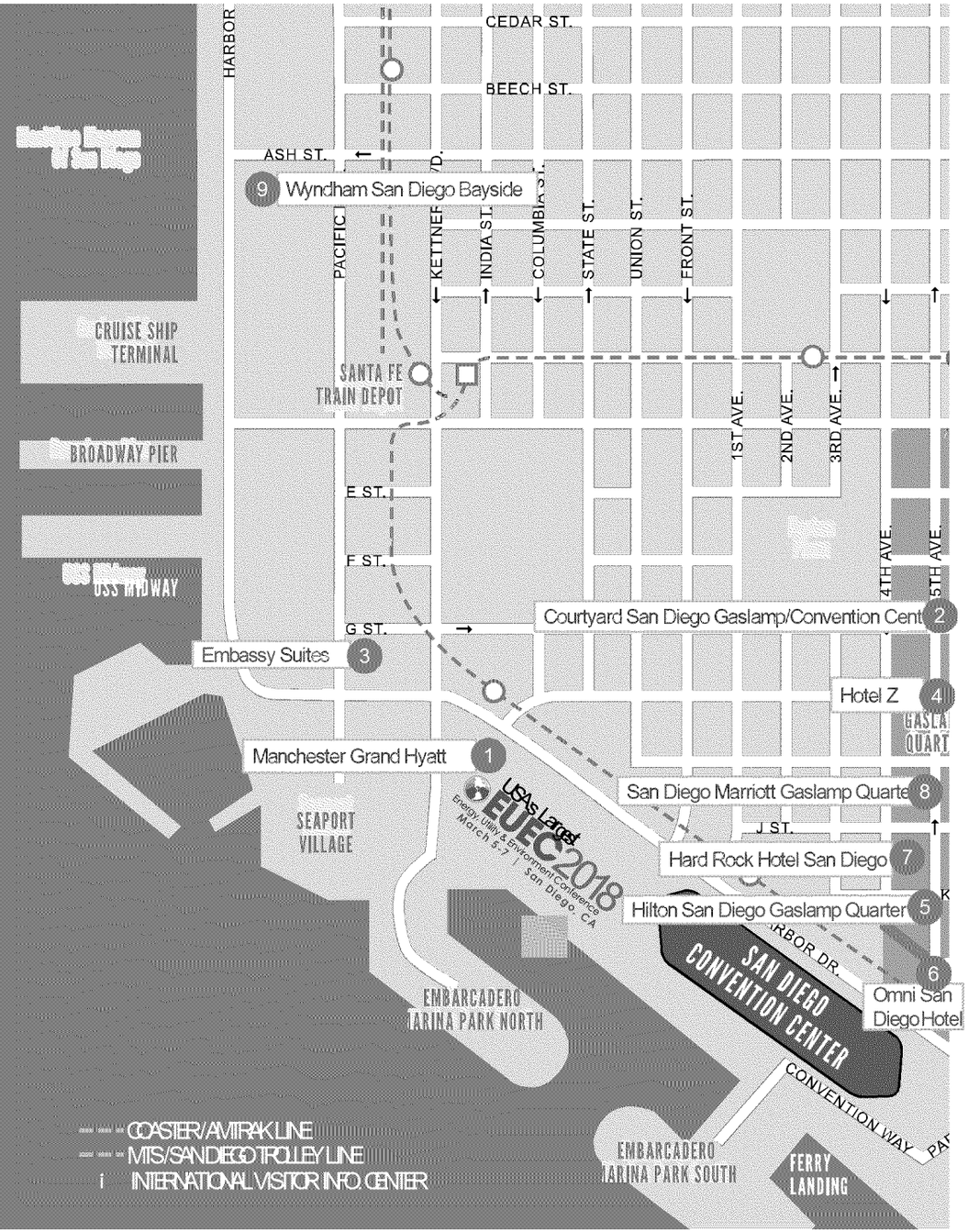

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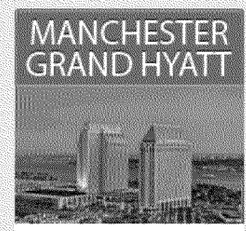

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Eric Hiser, Jorden, Hiser & Joy, PLC
Phone: 480-505-3927
Email: ehiser@jordenbischoff.com

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Robert Paine, CCM, QEP (AECOM)
Phone: 978-905-2352
Email: bob.paine@aecom.com

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Workshop 3 - Room 4

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Clement Joly, SoftInWay
Email:
TBD

Workshop 4 - TBD

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TBD, ESC
phone:
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Ben Sehgal, California Air Resources Board
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Chris Lyons, Solar Turbines
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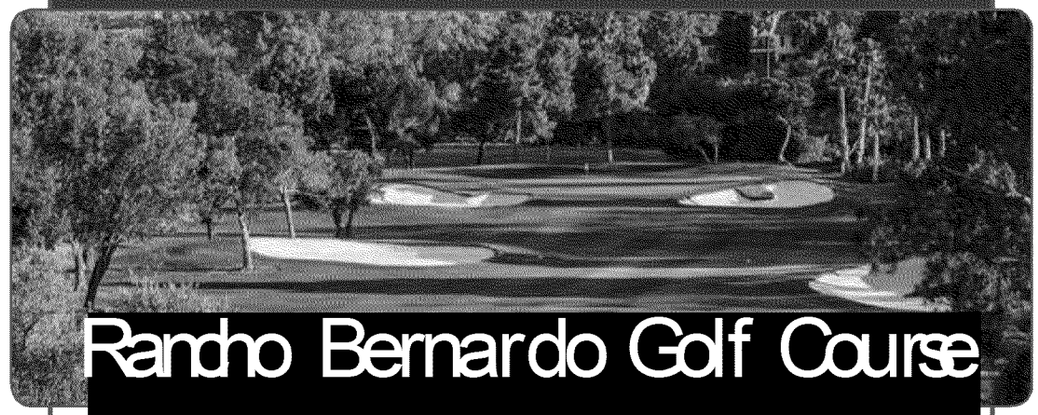

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Cc: James D. Elliott[jelliott@spilmanlaw.com]
From: Sarah D. Stoner
Sent: Wed 8/9/2017 8:23:54 PM
Subject: Docket No. EPA-HQ-OAR-2010-0505 - Comments of the Independent Producers
Independent Producers' Comments on Proposed Two-Year Stay.pdf

Please find attached the Comments on behalf of the Independent Petroleum Association of America ("IPAA"), American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), Oklahoma Independent Petroleum Association ("OIPA"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Products & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers") regarding the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements at 82 Fed. Reg. 27,645 (June 16, 2017), Docket No. EPA-HQ-OAR, 2010-0505, which was electronically submitted today at regulations.gov.

Please note that the Comments include attachments of the Petition for Reconsideration and Comments previously submitted by the Independent Producers.

Please contact the undersigned if you have any problems opening this document.
Thank you.

Sent on Behalf of

James D. Elliott
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101

Mechanicsburg, PA 17050
Ex. 6 office
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717.795.2743 - fax
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James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

August 9, 2017

The Honorable Scott Pruitt, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

VIA E-MAIL AND E-FILING

Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements at 82 Fed. Reg. 27,645 (June 16, 2017)

Docket ID No. EPA-HQ-OAR-2010-0505

Dear Administrator Pruitt:

The following comments are submitted on the above-referenced proposed rule ("Proposed Rule") on behalf of the following national and state trade associations: the Independent Petroleum Association of America ("IPAA"), American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), Oklahoma Independent Petroleum Association ("OIPA"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Products & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers"). The Independent Producers have participated individually or through IPAA in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011). While most of the Independent Producers represent companies that engage in large volume hydraulic fracturing horizontal or unconventional drilling, a significant portion of their membership is also comprised of "mom and pop" operations that engage in some form of hydraulic fracturing, generally involving vertical wells drilled into geological formations currently referred to as conventional wells. From the beginning of these rulemakings, most of the Independent Producers have tried to explain to the EPA that their "one-size-fits-all" approach to regulating this industry is inappropriate. The Proposed Rule represents another, necessary, opportunity to work with the EPA to tailor 40 C.F.R. Part 60, Subpart OOOOa ("Subpart OOOOa") to reduce the impact on the Independent Producers and their individual members while still providing adequate

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protection of the environment. The Independent Producers' Petition for Reconsideration submitted on August 2, 2016, to the EPA outlines the primary issues that should be addressed during the two-year time period set forth in the Proposed Rule.[1] As a result of various factors, including the regulatory burden, many individual members of the Independent Producers have not drilled a single well in the past five years. The Proposed Rule will have a tremendous benefit to the Independent Producers and their individual members, while having little to no negative impact on the environment. The proposed two-year time period is entirely appropriate for the Independent Producers to educate the new Administration on their concerns as well as make the appropriate and necessary changes to current regulations.

A. The EPA's Proposed Two-Year Stay is Reasonable and Authorized Under the Law.

On July 27, 2017, the American Petroleum Institute ("API") submitted comments on the Proposed Rule that focused on the legal authorities available to the EPA in order to take the proposed actions set forth in the Proposed Rule (EPA-HQ-OAR-2010-0505-10577). API's comments outline three principal means to effecting the two-year "stay": 1) extend the relevant compliance deadlines in Subpart OOOOa for a period of two years while the EPA evaluates the various issues raised in Petitions for Reconsideration pursuant to its authority in Section 111 of the Clean Air Act ("CAA"); 2) issue a stay under Section 705 of the Administrative Procedure Act, which authorizes a stay pending judicial review when justice is required; or 3) issue a stay pursuant to the EPA's general rulemaking authority under CAA Section 301(a). The Independent Producers incorporate by reference and endorse API's July 27, 2017 comments focusing on the EPA's legal authorities.

Regardless of the legal authority for the EPA's Proposed Rule, whether characterized as a "stay" or extension of compliance deadlines, fairness and justice for the Independent Producers' individual members that are disproportionally impacted by Subpart OOOOa and 40 C.F.R. Part 60, Subpart OOOO ("Subpart OOOO") justify the EPA's Proposed Rule. From the beginning of these related rulemakings in 2011, IPAA and many of the individual associations and their individual members have tried to explain the physical differences, economic differences, and differences in environmental impacts from the considerably smaller vertical and conventional operations that were swept into Subpart OOOOa and Subpart OOOO. Representatives from the Independent Producers traveled to the EPA's office in Research Triangle Park, NC, and met with representatives from the EPA prior to finalization of both Subpart OOOO and Subpart OOOOa. During these meetings there was considerable focus on the few possible exemptions that would provide some relief from reduced emission completions and fugitive emissions reduction measures for "low pressure wells" and "low production wells." The existence of the provisions related to low pressure wells and low production wells had the potential to considerably reduce the regulatory burden on certain vertical wells and conventional operations, many of which constitute small entities or small businesses under the Small Business Regulatory Enforcement Fairness Act.

[1] A copy of the Independent Producer's August 2, 2016 Petition for Reconsideration is attached for inclusion in the Proposed Rule's administrative record.

Representatives of the Independent Producers participated in the Small Business Advocacy Review Panel associated with Subpart OOOOa in 2015. The comments of IPAA and other individual associations filed during the rulemaking process for Subpart OOOO and Subpart OOOOa had little impact on the final versions of the rules.[2] The EPA has legal authority to finalize the Proposed Rule and utilize the two-year period to evaluate the factual issues not addressed by the previous Administration.

B. The Impact of Proposed Rule for Certain Individual Members of the Independent Producers is Critical: Stay in Business or Close Up Shop.

As explained in the meetings with the previous Administration and in the Independent Producers' attached comments on Subpart OOOO and Subpart OOOOa, the leak detection and repair ("LDAR") requirements as applied to low production wells is likely to make many of these wells uneconomical for the Independent Producers.[3] Certain members of the Independent Producers entire business consists of low production wells. In many cases, an operator will forgo "modifying" an existing low production well because of the costs of the LDAR requirements. The EPA has failed to quantify in any meaningful way the emissions associated with leaks from low production wells. As the Independent Producers explained in their Petition for Reconsideration, the EPA's logic and reasoning in Subpart OOOOa is internally inconsistent. The EPA assumes that replacing equipment that increases production will increase emissions because of pressure and production. Yet the EPA ignored that reality when it came to low production wells and indicated pressure and production did not play a role in emissions – and instead claimed that it was a function of the number of components and connections. That is manifestly unfair and the provisions need to be stayed or the compliance deadline needs to be extended until the EPA can better understand the quantity of emissions from leaks at low production wells and the costs associated with the LDAR requirements, especially as they apply to small entities. To many, the impact of the Proposed Rule means that they can continue to operate while the EPA fairly and appropriately addresses the issue. The EPA reversed course without adequate explanation and even the United States Court of Appeals for District of Columbia Circuit ("DC Circuit Court") failed to meaningfully address the EPA's internally inconsistent logic between emissions associated with modifications and low production wells. The DC Circuit Court dismissed the issue by saying that the EPA failed to cite the inconsistent logic as a reason for granting reconsideration in its original grant of reconsideration of the removal of the low production exemption in the April 18, 2017

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[2] Copies of the comments IPAA took the lead in preparing and filed during the various Subpart OOOO and Subpart OOOOa rulemakings are attached to this comment letter for inclusion in this administrative record. Not every member of the Independent Producers participated in every set of comments.

[3] Although Subpart OOOOa defines a marginal well as producing 15 barrels of oil ("bbl") (which equates to about 90 million cubic feet ("Mcf") of natural gas) per day or less, the average marginal well production in the US is much lower. The Interstate Oil and Gas Compact Commission's 2015 Marginal Wells: Fuel for Economic Growth Report ("2015 Marginal Wells Report") indicates that the average marginal oil well produces 2.0 bbls/day and average natural gas marginal well produces 14.2 Mcf/day. At such low production, profit margins are thin and additional regulatory burden could easily make many uneconomical. According to the 2015 Marginal Wells Report, the elimination of both marginal oil and natural gas wells in 2015 would result in an estimated direct loss of 57, 560 jobs in the oil and gas sector and $4.4 billion in direct earnings within the surveyed states.
See http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf

letter to certain petitioners. That did not make the issue disappear, it was simply an expedient way to dismiss it. The issue still remains, and when the impact of low production exemption could be a "bet the farm" proposition, the EPA is certainly justified in revisiting the issue and staying those requirements.

C. The Two-Year Duration is Appropriate.

The issues raised in the Petitions for Reconsideration are numerous, and some are more complex than others. Based on the lack of reliable emissions estimates and cost estimates related to LDAR, in general, and at low production wells, specifically, it is important that the EPA interface with all stakeholders, develop an appropriate protocol for collection of emission data, and then calculate the cost of compliance – especially as it relates to small entities. Two years is an appropriate time period to undertake the aforementioned process. The Independent Producers believe many of the requirements subject to Petitions for Reconsideration are a function of the previous Administration rushing to judgment and solidifying one's legacy before leaving office. Representatives from the Independent Producers met with the EPA after Subpart OOOOa was finalized to address some of the requirements that were of greatest concern to their members, *e.g.*, removal of the low production well exemption and the requirement that a separator be onsite during well completions. The representatives explained to the EPA, for a second time (the first being with Subpart OOOO), that certain vertical wells and "energized" fractures cannot operate a separator – it is simply not technically feasible. There seemed to be some acknowledgment on the part of the EPA that the requirement for a separator onsite regardless of the type of fracture did not make sense. Revisions to provisions, such as having a separator onsite during the entire completion, might not require two years and could be proposed earlier. The Independent Producers appreciate certain advantages to waiting until a "critical mass" of issues are resolved before making a final determination on the issue for reconsideration. The Independent Producers are willing to work with EPA and stakeholders to perhaps agree on certain issues that could be addressed in less than two-years.

D. Conclusion.

The beneficial impact of the Proposed Rule to the Independent Producers and their individual members is significant. The impact of the Proposed Rule on the environment is minimal. The duration of the Proposed Rule is entirely appropriate considering the complexity of certain issues. A significant majority of the Independent Producers' concerns raised in the attached comments were not adequately addressed in the previous rulemakings associated with Subpart OOOO and Subpart OOOOa. Consequently, the Independent Producers challenged the final rules in court and petitioned the EPA for reconsideration. The EPA's Proposed Rule under the new Administration is entirely appropriate.

If the EPA has any questions or concerns, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Amanda Gunasekara, EPA (via E-mail)
Elliott Zenick, EPA (via E-mail)
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August 2, 2016

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The following trade associations hereby submit this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa" or "Methane NSPS"). We request that you take the time to review what and who these trade associations represent and not simply jump to the issues we are seeking reconsideration of. Many of these trade associations have been around since or before the 1950s. The trade associations represent the "independent" exploration and production companies – from the "mom and pop" operations to some of the larger producers in the country – but that is all they do and it is all they know. Subpart OOOOa, as finalized, will have a disproportionate impact on independents and especially independents that constitute "small business" under the Regulatory Flexibility Act. The issues raised in this petition fall into two categories: 1) issues that are entitled to reconsideration under Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule; and 2) issues the independents commented on, either through their trade association or as an individual company, that the U.S. Environmental Protection Agency ("EPA" or "Agency") failed to address in the final rule and that will have devastating impacts to the exploration and production segment of the industry if not addressed.

The national and state level trade associations joining in and filing this petition for reconsideration, collectively referred to as the "Independent Associations," are described below.

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed

voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The American Exploration & Production Council ("AXPC") is an incorporated national trade association representing 29 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and the production of oil and natural gas. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways.

The Domestic Energy Producers Alliance ("DEPA") is a nationwide collaboration of 25 coalition associations, representing about 10,000 individuals and companies engaged in domestic onshore oil and natural gas production and exploration. Founded in 2009, DEPA gives a loud, clear voice to the majority of individuals and companies responsible for enduring work to secure our nation's energy future.

The Eastern Kansas Oil & Gas Association ("EKOGA") is a nonprofit organization founded in 1957 to become a unified voice representing the unique interests of eastern Kansas oil and gas producers, service companies, suppliers and royalty owners on matters involving oil and gas regulations, safety standards, environmental concerns and other energy related issues.

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive, and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of their state.

The Indiana Oil and Gas Association ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does and will affect the business of this industry. INOGA is a

501(c)(6) trade association incorporated as Non-Profit Domestic Corporation under the statutes of Indiana.

Since 1940, the International Association of Drilling Contractors ("IADC") has exclusively represented the worldwide oil and gas drilling industry. IADC's contract-drilling members own most of the world's land and offshore drilling units that drill the vast majority of the wells producing the planet's oil and gas. IADC's membership also includes oil-and-gas producers, and manufacturers and suppliers of oilfield equipment and services. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

The Kansas Independent Oil & Gas Association ("KIOGA") is a nonprofit organization founded in 1937 to represent the interests of oil and gas producers in Kansas, as well as allied service and supply companies. Today, KIOGA is a trade association with over 4,200 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources.

The Kentucky Oil & Gas Association ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Michigan Oil And Gas Association ("MOGA") represents the exploration, drilling, production, transportation, processing, and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 850 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies, and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The National Stripper Well Association ("NSWA") was founded in 1934 as the only national association *solely* representing the interests of the nation's smallest and most economically-vulnerable oil and natural gas wells before Congress, the Administration and the Federal bureaucracies. It is the belief of NSWA that producers, owners, and operators of marginally-producing oil and gas wells have a unique set of needs and concerns regarding federal legislation and regulation. NSWA is a member based trade association with nearly 800 members nationwide across 43 states.

The North Dakota Petroleum Council ("NDPC") is a trade association representing more than 590 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, and storage, as well as mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky

Mountain Region. Established in 1952, NDPC's mission is to promote and enhance the discovery, development, production, transportation, refining, conservation, and marketing of oil and gas in North Dakota, South Dakota, and the Rocky Mountain region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Founded in 1955, the Oklahoma Independent Petroleum Association ("OIPA") represents more than 2,500 individuals and companies from Oklahoma's oil and natural gas industry. Established by independent oil and natural gas producers hoping to provide a unified voice for the industry, OIPA is the state's largest oil and natural gas association and one of the industry's strongest advocacy groups.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 as the Independent Oil and Gas Association of Pennsylvania ("IOGA of PA") to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Effective April 1, 2010, IOGA of PA and another Pennsylvania trade association representing conventional oil and natural gas producers, Pennsylvania Oil and Gas Association ("POGAM"), merged and the name of the merged organization changed to its present name. PIOGA's membership currently is approximately 500 members: oil and natural gas producers developing both conventional and unconventional formations in Pennsylvania; drilling contractors; service companies; engineering companies; manufacturers; marketers; Pennsylvania Public Utility Commission-licensed natural gas suppliers ("NGSs"); professional firms and consultants; and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations, as well as the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and

trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state.

Chartered in 1915, the West Virginia Oil and Natural Gas Association ("WVONGA") is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing.

The Independent Associations respectfully request the Agency reconsider the following issues.

A. SECTION 307(D)(7)(B) RECONSIDERATION ISSUES

1. The low production well (15 barrels of oil equivalent ("boe")/day) exemption from leak detection and repair ("LDAR") and reduced emission completions ("RECs") requirements should be reinstated in the final rule and the requirements regarding low production wells should be stayed pending reconsideration.

In the proposed rule, EPA sought comment on and proposed to exclude low production wells (i.e., those with an average daily production of 15 barrel equivalents or less per day) from REC and LDAR requirements. 80 Fed. Reg. 56633-34, 56639, 56665 (Sept. 18, 2015). The trades representing the independents uniformly supported the low production well exemptions. Based on the preamble discussion of the low production well exemption, EPA listened to, understood, and accepted the arguments and comments set forth by "small entities" during the Small Business Advocacy Review Panel ("Panel") process, in compliance with Section 609(b) of the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA"). Small entity representatives ("SERs"), including trade associations that are part of this petition, met with the Panel, which included EPA personnel, on May 19, 2015, and June 18, 2015, and submitted written comments. The SERs' message was clear – the potential REC and LDAR requirements would be the most onerous aspect of any additional controls on their operations. The SERs explained how and why these potential requirements would disproportionality impact small entities. The SERs explained the physical differences associated with low production wells (e.g., primarily pressure and volume) and the marginal profitability of low production wells. EPA seemed to "get it" and stated in the preamble:

> We believe the lower production associated with these wells [low production wells] would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement

> on small businesses, in particular where there is little emission reduction to be achieved.

80 Fed. Reg. 56639. Numerous oil and natural gas trade associations, including many of the parties to this petition filed comments in support of the exemptions and the rationale behind them.

Despite the information provided to EPA during the SBREFA process and Final Report of the Panel, EPA reversed course in the version of Subpart OOOOa and did not provide the low production exemption from either the REC or LDAR requirements. In the preamble to Subpart OOOOa that "one commenter" stated that low production wells have the "potential" to emit high fugitive emissions; "another commenter" stated that the LDAR survey should be conducted quarterly or monthly; and "one commenter" provided an estimate that a "significant" number of wells would be excluded under the low production well exemption. What appears to be EPA's principal reason for reversing course is that

> [S]takeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

81 Fed. Reg. 35856. EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."

The estimation or correlation of fugitive emissions with the number or types of components at low production versus non-low production wells was not discussed during the Panel process nor was comment sought by EPA in the proposed rule. If EPA proposed to correlate fugitive emissions at low production well sites with the number or types of components – in place of operating parameters such as line pressure and volume, independents would have been put on notice that additional information and comments were needed on the issue. No such comment was sought and EPA rationale and revocation of the low production well exemption is confounding. An administrative stay of the REC and LDAR requirements to low production wells is warranted pending outcome of the reconsideration proceeding. Although the effective date of the requirements has been extended 180 days, the impact of the regulations is immediate on low production wells. The marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys. Similarly, low production wells that are currently in the planning stage will be reevaluated to take into consideration the

additional costs of RECs and it is likely that the plans to drill many wells will be scrapped. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

2. **The requirement in Section 60.5375a of Subpart OOOOa that requires a separator be "onsite during the entirety of the flowback period" was not part of the proposal and imposes an unnecessary cost on many conventional wells drilled by independents.**

From the inception of the Subpart OOOO rulemaking, independent operators have informed the Agency that operating parameters during flowback of certain hydraulically fractured wells, often what is referred to as "conventional" wells, are such that a separator does not "work" – or as EPA has focused on is not technically feasible. EPA initially seems to understand this point and states:

> … we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

81 Fed. Reg. 35881. Independent Associations take issue with the conclusion that requiring a separator onsite throughout the entire flowback period would incur no cost. The cost of having the separator on site is a significant cost and could be a limitation on the operations of certain operators. The existing regulations make clear that a separator must be utilized during the separation flowback stage and EPA has increased the record keeping and monitoring associated with the different stages of flow back. In addition to these requirements, there is the general duty clause to reduce emissions. The requirement to have a separator onsite throughout the flowback process is an unnecessary cost to many independent operators that provides no economic benefit. The proposed rule did not contemplate requiring a separator to be onsite throughout the flowback process and in fact inferred just the opposite. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

3. **Subpart OOOOa added a variety of requirements associated with "technical infeasibility" that were not purposed or even mentioned in the proposed rule**

that increase the cost of compliance with disproportionally impacts on independent operators.

While the Agency has appropriately accepted the concept that it is not technically feasible to implement certain controls, EPA added a number of requirements in Subpart OOOOa that were not proposed or discussed in the proposed rule:

- The final rule requires that Professional Engineers ("PE") certify connections of pneumatic pumps (§60.5393a) or closed vent systems (§60.5411a(d) are not technically feasible at brownfield sites. The certification by a PE will add considerable cost with no demonstrated benefits. As with many of these requirements. the independent operators do not have the ability in-house to meet these requirements and are dependent on third-party contractors. As EPA pushes the envelope on new/additional requirements, economies of scale favor the larger operators and to the extent the contractors are available for hire, it comes at a premium cost for the smaller entities and/or independent operators.
- Without discussion in the proposed rule, the Agency has also removed the "technical infeasibility" option for controls at "greenfields." Neither the proposed rule nor Subpart OOOOa define what constitutes a brownfield versus a greenfield. At some point in time a greenfield becomes a brownfield. Not only does the proposed rule fail to mention the concept of brownfield versus greenfield, Subpart OOOOa fails to provide any differentiation.
- The additional recordkeeping requirements added in Subpart OOOOa, at end of §60.5420a(c)(1)(iii)(A), associated with technical infeasibility, which were not part of the proposed rule, demonstrates that the Agency fails to understand that such requirements disproportionally impact small entities and many independent producers and operators.

The additional requirements associated with technical infeasibility were not only not addressed in the proposed rule, but the Agency failed to consider and address the disproportionate impact they would have on independent operators.

B. ADDITIONAL ISSUES IN NEED OF REVISION

The following issues were arguably addressed in some manner during the SBREFA and/or notice and comment process, but based on a review of the record, the Independent Associations believe they warrant additional discussion. The Independent Associations will provide the Agency additional information on these issues of concern.

1. The definition of "modification" as it relates to refractured wells and the LDAR requirements needs to be clarified and changed. The refracturing of wells does not necessarily mean emissions will increase. Emissions must increase to meet the NSPS definition of modification. As currently defined, Subpart OOOOa would unjustifiably subject "existing sources" that have not necessarily been modified to extensive and costly requirements.

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of "low pressure well."

3. There should be an "off ramp" for the LDAR requirements when existing wells or new wells become "low production" or marginal wells.

4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.

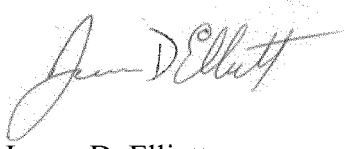
5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.

6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.

7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

As indicated above, the Independent Associations will provide additional information on the issues raised above. In the interim, if the EPA has any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,



James D. Elliott

Counsel to the Independent Associations

cc: Janet McCabe, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

AXPC American Exploration & Production Council

December 4, 2015

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

VIA ELECTRONIC MAIL

Re: Comments for Three Regulatory Proposals issued September 18, 2015:

1) **Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (80 Fed. Reg. 56,593)**

2) **Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry (80 Fed. Reg. 56,577)**

3) **Source Determination for Certain Emission Units in the Oil and Natural Gas Sector (80 Fed. Reg. 56,579)**

Dear Administrator McCarthy:

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC) (collectively, IPAA/AXPC).[1]

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will most directly be impacted by the U.S. Environmental Protection Agency (EPA) policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop about 95 percent of American oil and gas wells, produce 54 percent of American oil, and produce 85 percent of American natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

AXPC is a national trade association representing 30 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and production of oil and natural gas. Moreover, our members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying innovative and

[1] For ease of reference, these comments include an Acronym Index, attached hereto as "Attachment A."

advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from unconventional sources.

Additionally, they are joined by the American Association of Professional Landmen (AAPL), the Association of Energy Service Companies (AESC), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), the US Oil & Gas Association (USOGA), and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Idaho Petroleum Council
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers' Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers

Texas Oil and Gas Association
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Slope Colorado Oil & Gas Association
West Virginia Oil and Natural Gas Association

Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be most significantly affected by the actions resulting from these regulatory proposals. In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. IPAA/AXPC also endorses and supports the comments of the Western Energy Alliance (WEA) and the American Petroleum Institute (API) submitted on the proposed rules referenced above.

As an initial matter, these comments are designed to address the three aforementioned proposed regulatory actions simultaneously and will be submitted to all three dockets as all three proposals target the oil and natural gas industry, and certain responses and arguments from IPAA/AXPC are applicable to all of the proposals. Additionally, comments on all three proposals were initially due November 17, 2015. IPAA requested an extension of the 60-day comment period on October 2, 2015, due to the complexity and breadth of the proposed regulations and that certain key supporting documents were not available in the docket for public review when the EPA published the proposals in the Federal Register on September 18, 2015. In late October/early November various informed parties who had requested additional time to comment learned that they would have until December 4, 2015. On November 13, 2015, the extension was published in the Federal Register.

EXECUTIVE SUMMARY

These comments raise a number of key issues associated with EPA's proposals for Clean Air Act (CAA or Act) New Source Performance Standards (NSPS), Control Technique Guidelines (CTG) and Source Determination for oil and natural gas production facilities.

EPA justifies its proposals in the context of the Administration's Climate Action Plan with a specific target of reducing methane emissions from the oil and natural gas sectors by 40-45 percent during the time period from 2012 through 2025. However, as these comments demonstrate, EPA's proposals are unnecessary, unjustified, poorly developed and counterproductive.

First, the Administration proclaims its intent to reduce methane emissions by 40-45 percent from the oil and natural gas sectors. At the same time, it takes credit for its 2012 volatile organic chemical/methane emissions regulations in these sectors that exceed its own target. Moreover, it fails to recognize that much of the reduction it seeks has occurred since 2012 from voluntary industry actions. The oil and natural gas production sector is 1.07 percent of the national Greenhouse Gas Inventory and its methane emissions will continue to drop because of industry emissions management. Consequently, any justification for additional regulation must

be thoroughly weighed based on cost effectiveness and economic consequences. EPA's proposals fail these tests.

Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently implementing programs; none of which parallel EPA's proposals. Experience with those state efforts demonstrates that emissions patterns result from a few high emissions sources that can be managed quickly with sustained reductions. EPA's proposal to lock in an unworkable program for at least 5 years is arbitrary and inappropriate. EPA should await the analysis of state programs to determine whether an NSPS is logical or necessary.

Third, EPA also proposed a volatile organic compound (VOC) CTG for Ozone nonattainment areas. This proposal fails to comply with the Agency's fundamental responsibility of developing Reasonably Available Control Technology (RACT). Instead, EPA largely transposes the same requirements in the 2012 NSPS and those proposed in this regulatory action from new sources to existing ones. In doing so, EPA fails to determine whether these new facility requirements are economically appropriate as CTG for existing sources on a national basis.

Fourth, by linking its CTG proposal to its Climate Action Plan, EPA fails to address the need for the CTG with regard to Ozone nonattainment. Yet, the threshold question for these regulations is whether they are necessary and appropriate for attainment of the Ozone National Ambient Air Quality Standards (NAAQS). If fact, based on EPA's analysis of the regulatory framework to attain the recently revised Ozone NAAQS, EPA demonstrates the CTG are wholly unnecessary. Prior to proposing these CTG, EPA concluded that all but a few areas of the country will meet the new Ozone NAAQS by 2025 using national, federal regulatory requirements. Consequently, for these areas, the proposed CTG are excessive regulations. For the remaining enduring Ozone nonattainment areas, if there are oil and natural gas production operations that need to be addressed, they can be managed through local determinations of Reasonably Available Control Measures (RACM) and do not require CTG.

Fifth, because these CTG are unnecessary, their likely impact will be the inappropriate restriction of economic growth in Ozone nonattainment areas. Given that EPA has concluded that Ozone NAAQS attainment will be achieved without these CTG, these CTG will remove emissions that could be used as CAA required new source offsets. Therefore, they would unnecessarily impede economic growth that would otherwise occur.

Sixth, in its proposal to address Source Determination for oil and natural gas production facilities, EPA should recognize that new facilities should be based on a narrow definition that hones closely to the approach EPA has used under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) program. Where there are issues regarding scope, the source determination should be based on the sites being contiguous in addition to sharing the same Standard Industrial Classification (SIC) Code and being under common control.

These comments will expand on the issues raised above and other more specific ones. Ultimately, however, IPAA/AXPC argues that EPA's NSPS and CTG proposals must be withdrawn, reconsidered and revised to be consistent with the Administration's own Climate Action Plan objectives and its assessment of the capability of the nation to meet the revised Ozone NAAQS. To do otherwise would arbitrarily impose excessive regulation on the oil and natural gas setoff for no purpose other than to expand the already burdensome federal regulatory program.

I. EPA's Additional New Source Performance Standards for the Exploration and Production Segment and Control Technique Guidelines for Existing Sources are Unnecessary and Misplaced.

EPA's proposed NSPS targeting methane emissions from the exploration and production segment of the oil and natural gas sector are unnecessary, unwarranted, and wasteful – not only to those subject to the regulations but to the state and federal regulators who must implement the rules if EPA does not change its course. Similarly, proposing essentially the same set of controls on existing sources in nonattainment areas (and ozone transport regions) using the proposed CTG with no additional economic justification/cost-benefit analysis is one more indication that EPA is rushing to judgment with its latest salvo of regulations. In April 2014, EPA acknowledged the lack of knowledge to regulate a variety of sources and implemented a White Paper process that sought additional technical information on a variety of sources.[2] Industry raised numerous concerns regarding EPA's lack of data regarding emissions from these sources and the cost/effectiveness of controls from these sources. Nonetheless, EPA proceeded headlong to promulgate its methane NSPS – relying heavily on the Regulatory Impact Analysis (RIA) from the VOC NSPS promulgated in 2012. The methane regulations need to "stand on their own" and be justified on their own, not simply as an "add-on" to the VOC NSPS.

These regulations will have a serious negative economic impact on American oil and natural gas production while providing marginal environmental benefit beyond the regulations EPA promulgated in 2012 to regulate VOCs from essentially the same set of production and exploration emission sources.[3] To understand the full impact, it is essential to put the entire issue in perspective.

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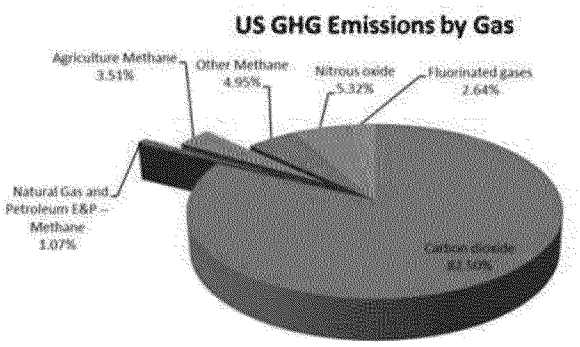
[2] U.S. Environmental Protection Agency, Section on Oil and Natural Gas Air Pollution Standards, *Methane*, *available at* http://www3.epa.gov/airquality/oilandgas/methane.html.

[3] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

From 2008 through 2013, U.S. shale gas production grew 400 percent,[4] while methane emissions have declined 13.3 percent. According to 2013 EPA Greenhouse Gas (GHG) Reporting data, methane emissions from oil and natural gas exploration and production are 1.07 percent of total U.S. GHG emissions. Further reductions will occur because of "green" or "reduced emission completions" that are being phased-in through the 2012 regulations.[5] According to EPA's latest GHG Reporting Program: "[In 2013] reported methane emissions from petroleum and natural gas systems sector have decreased by 12 percent since 2011, with the largest reductions coming from hydraulically fractured natural gas wells, which have decreased by 73 percent during that period. EPA expects to see further emission reductions as the agency's 2012 standards for the oil and gas industry become fully implemented."[6] These reductions are remarkable, given that a major component of the 2012 standards, the reduced emission completion requirements, only became effective January 1, 2015.



In January 2015, the Administration announced its intent to initiate rulemaking to further reduce methane emissions from oil and natural gas systems, including the production sector.[7] Specifically, it announced a target of a 40-45 percent reduction in 2012 emissions by 2025. For the production and exploration segment of the oil and natural gas sector, additional regulations are unnecessary. As the Administration observed in its announcement:

> In 2012, the Environmental Protection Agency (EPA) laid a foundation for further action when it issued standards for volatile organic compounds (VOC) from the oil and natural gas industry. These standards, when fully implemented, are expected to reduce 190,000 to 290,000 tons of VOC and decrease methane

[4] U.S. Energy Information Administration, *available at* http://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm.

[5] In 2012, EPA finalized a Clean Air Act (CAA or Act)Section 111(b) NSPStargeting VOCs emissions from hydraulicallyfractured natural gas wells. This rulemaking also reduces methaneemissions as co-benefit. Methane and VOCs are emitted from oil and natural gas production facilities at thesametime from the same equipment. Consequently,reducing one also reducesthe other. The effects of the 2012 NSPS are still unfolding.

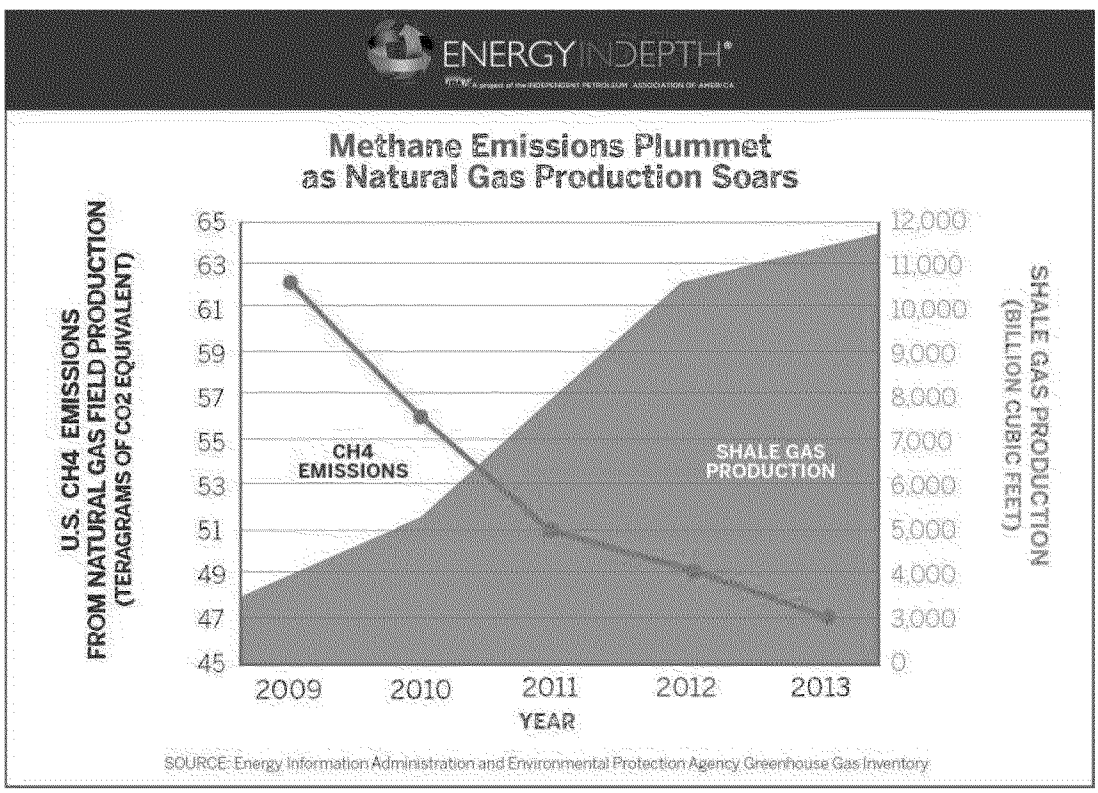
[6] Requirements for reduced emission completions on natural gas wells were promulgated in August 2012 but did not become effective until January 1, 2015. Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards, 79 Fed. Reg. 79,018 (Dec. 31, 2014) (codified at 40 C.F.R. pt. 60).

[7] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

> emissions in an amount equivalent to 33 million tons of carbon pollution per year.[8]

Over 99 percent of the EPA projected reductions occur from the exploration and production sector. In 2013, exploration and production emissions of methane were 71 million tons of CO_2 equivalent. Consequently, by EPA's own numbers, the 2012 NSPS regulations will reduce emissions by 46 percent. This reduction exceeds the emissions target percentage of the production sector of the oil and natural gas industry.

EPA attempts to argue that its regulations are needed because methane emissions "are projected to increase by about 25 percent over the next decade if additional steps are not taken to reduce emissions from this rapidly growing industry."[9] Yet, this statement is wholly inconsistent with the experience over the past several years in the exploration and production sector of the industry. This segment has demonstrated that growth in production not only provides more clean-burning, GHG-reducing product, it has been done while reducing methane emissions as the following graphic shows:



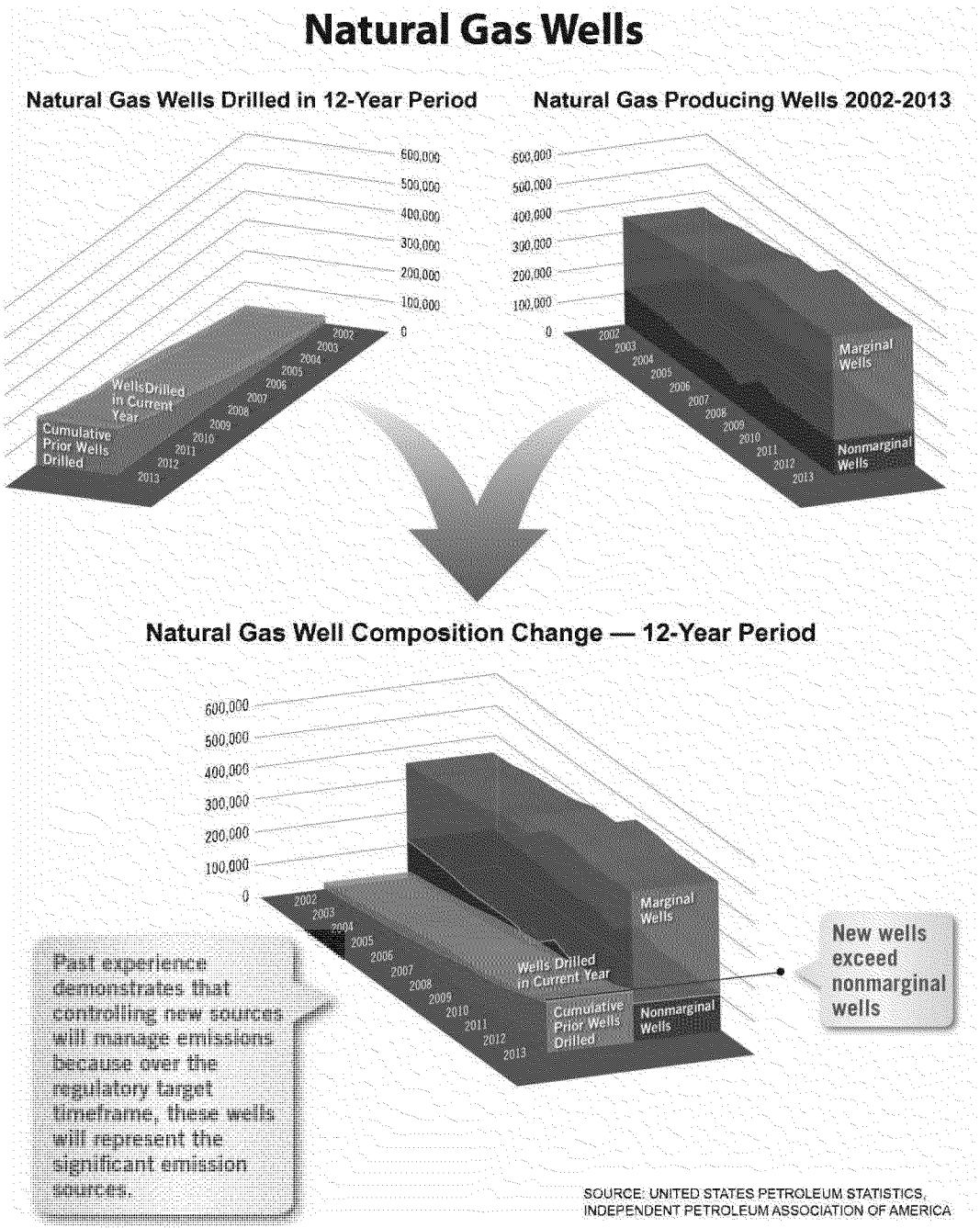
[8] *Id.*

[9] U.S. Environmental Protection Agency, Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

Significantly, these reductions in methane emissions have occurred prior to full implementation of the 2012 NSPS.

Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the Administration's objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. After the period of initial production, wells begin to decline – generally referred to as the "production decline curve." And as the production of the well declines, its ability to emit VOCs and methane into the atmosphere also declines. Emissions from these older wells will be a smaller portion of the 1.07 percent of emissions, yet EPA's decision to regulate methane directly under Section 111(b) of the CAA and proposed CTG subjects tens of thousands of existing wells to regulation. IPAA/AXPC questions the cost-effectiveness of the proposed requirements to existing sources. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in EPA's proposal.

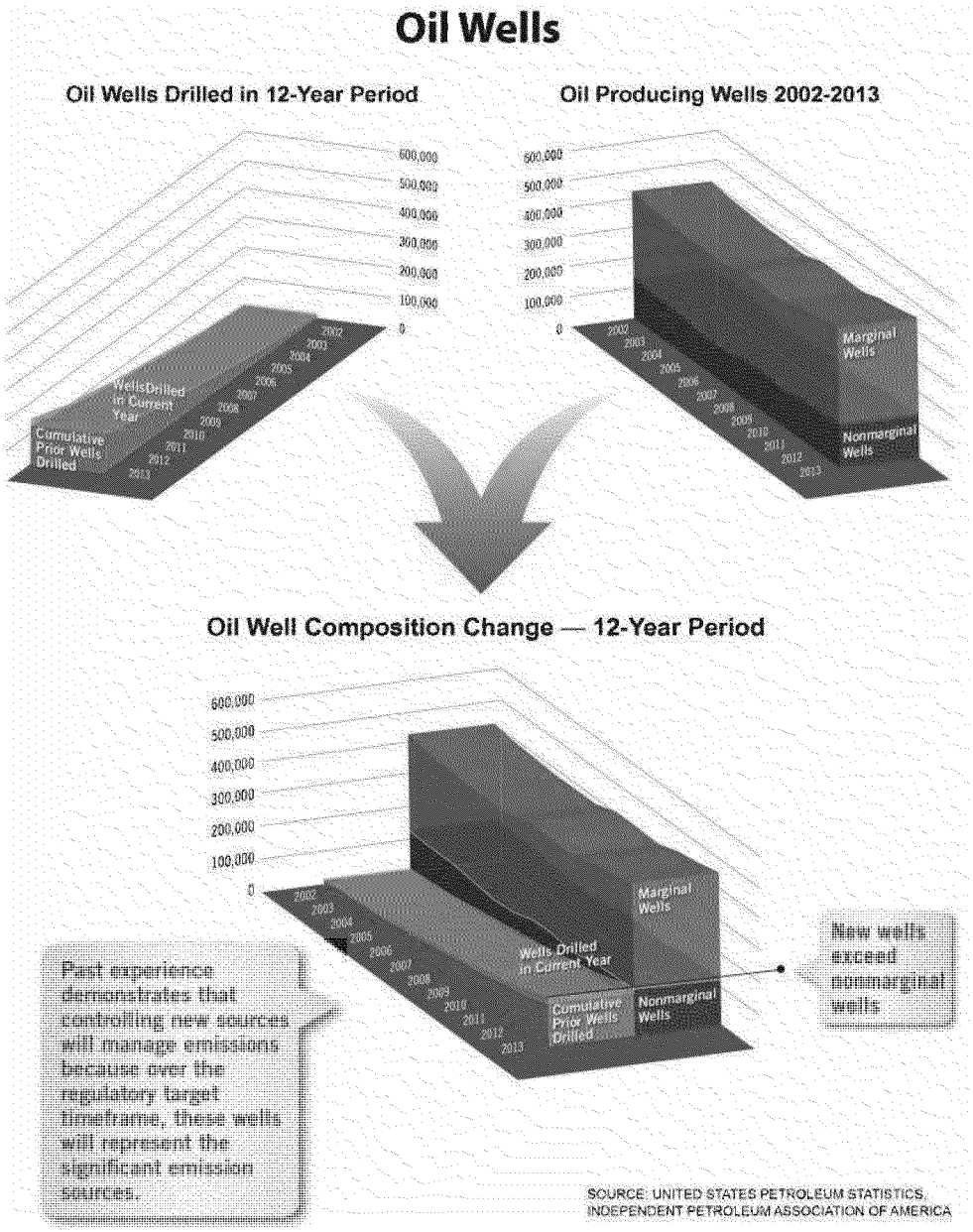
The declining nature of oil and natural gas wells also differentiates the exploration and production segment of the oil and natural gas sector from other segments further downstream where emissions remain fairly constant overtime. Ultimately, the production from the "new" wells declines to the point where they become "marginal" wells. These are defined as wells that produce 15 barrels/day of oil or less and 90 mscf/d or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells. However, these small individual wells account for about 20 percent of U.S. oil production and 13 percent of its natural gas production. Consequently, unlike manufacturing facilities where new facilities do not replace existing ones, in the oil and natural gas production industry, the implementation of technology on new wells will rapidly result in its application across the breadth of the industry as new wells become the predominant source of emissions for the industry. This can be understood by looking at past experience as shown in the graphs below:



As this graphic demonstrates, after 12 years wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost associated with reducing those incremental emissions will be greater than the cost of implementing controls on new or modified sources and will likely make many of the marginal wells uneconomic, causing them to be shut in/abandoned. The opportunity

cost or value of that last production is not offset by the minimal emissions reductions achieved by regulating existing sources.

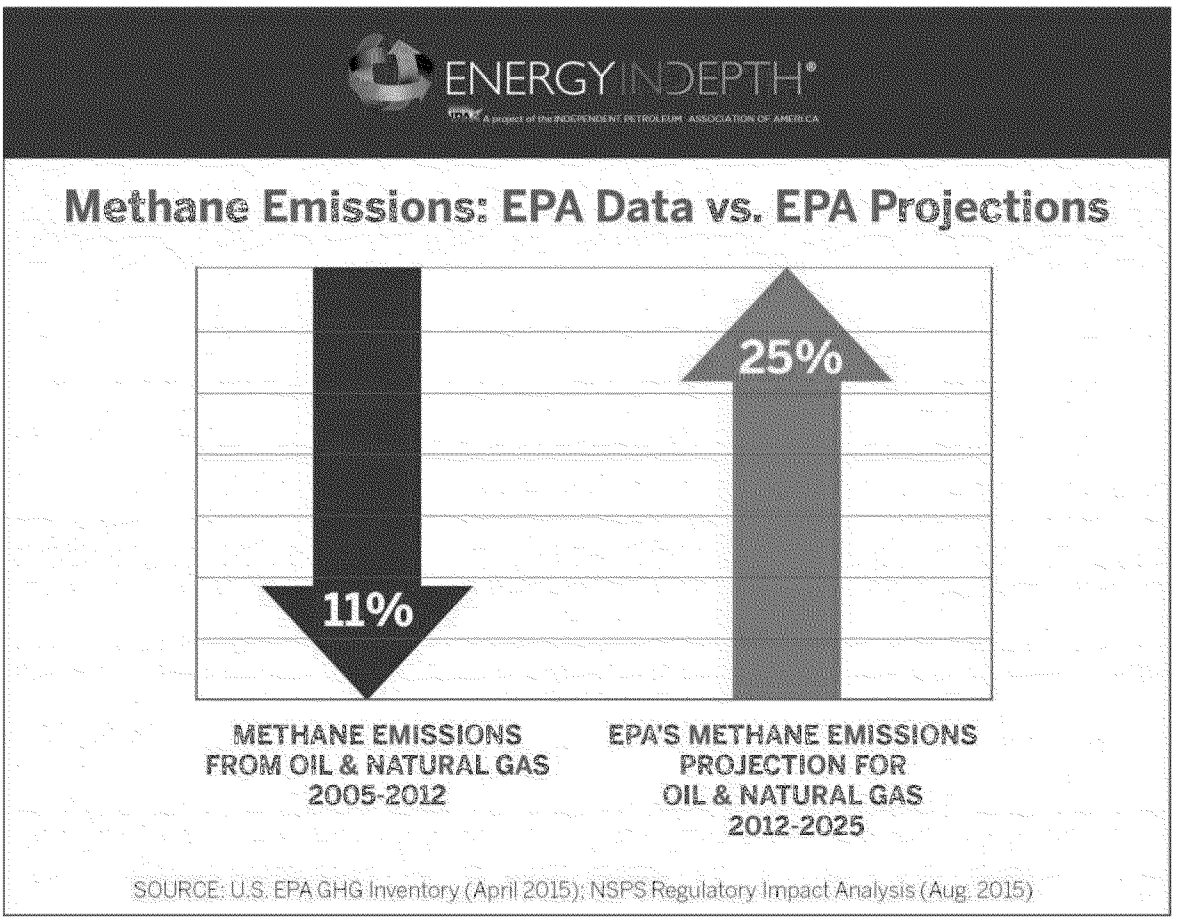
A similar pattern exists for oil wells as shown below:



While this analysis is based on past experience, if it were expanded to a 20-year period, it would show a similar trend and demonstrate that the use of new source regulations are more than adequate to address the Administration's interest in reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. EPA

has failed to adequately account for and justify subjecting existing exploration and production sources to regulation under Section 111 of the CAA or through the CTG.

As Energy In Depth (a research, education, and public outreach campaign supported by IPAA) recently reported, EPA's assumptions regarding methane emissions from the oil and natural gas industry are not supported by EPA's own data.

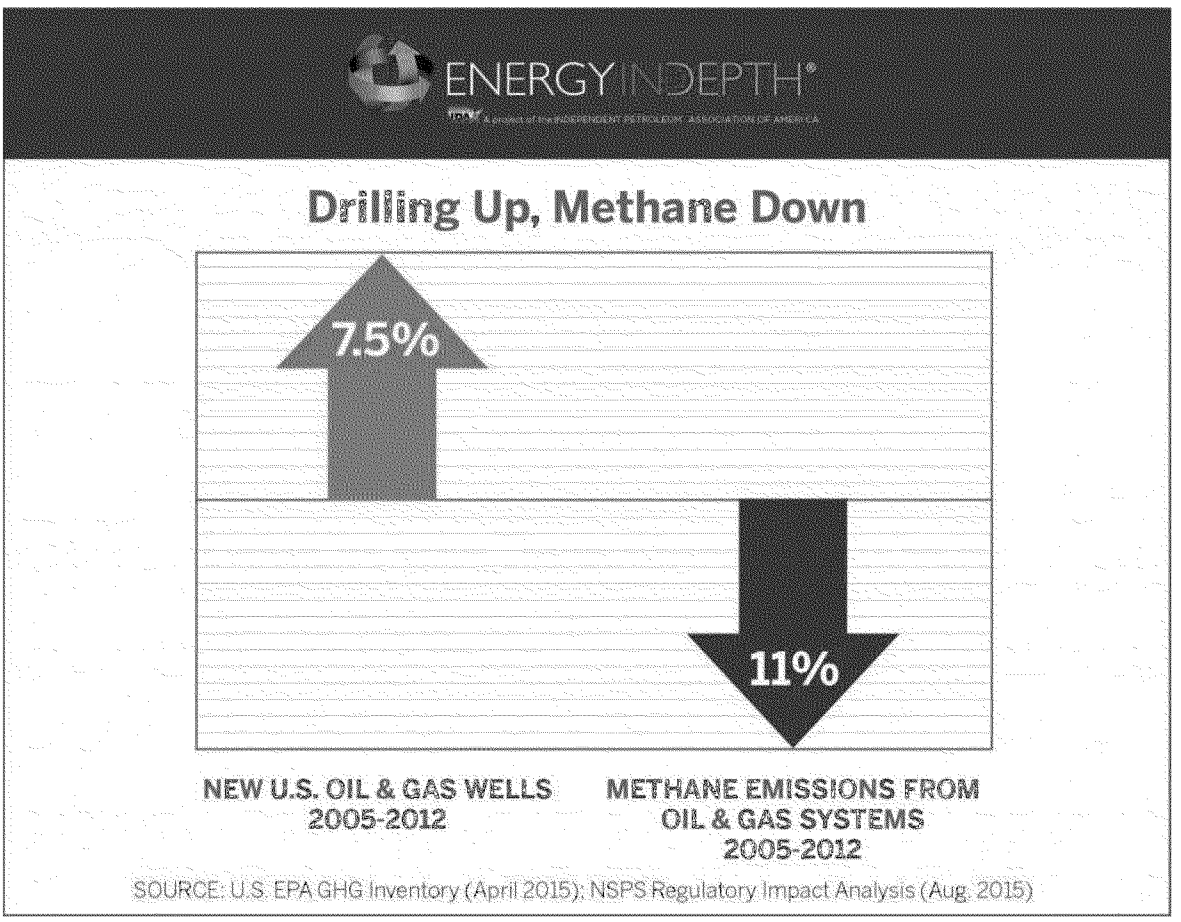


More specifically, Energy In Depth found:

- EPA projects methane emissions from the oil and natural gas sector will increase over the next decade, but **methane emissions from that sector have declined by more than 22 million metric tons** since 2005.
- Over the past decade, the United States added more than 86,000 new wells, during which **methane emissions from petroleum and natural gas systems fell by 11 percent**.
- EPA's flawed assumptions on methane emissions raise questions about the agency's cost-benefit calculation, and EPA could be **underestimating engineering costs by more than $10 million**.

- The EPA could also be **overstating the climate benefits of the rule**, since methane emissions may be significantly lower than EPA's projections.[10]

As discussed below, EPA's economic justification for it proposed regulations is problematic. But even the past does not support EPA's fundamental assumption that more drilling means more emissions:



EPA has projected that an increase in oil and natural gas activity will result in a 25 percent increase in methane emissions. But since 2005, methane emissions from U.S. oil and natural gas systems have fallen by a greater percentage than the number of new wells drilled.

IPAA/AXPC has repeatedly told EPA that additional regulation is not needed. Market forces drive the industry to minimize emissions. Unlike certain "products" in other industries with "emissions" that are a by-product or negative externality associated with the production, the "emission" of concern to EPA is the very product this industry brings to the market.

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[10] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/. IPAA/AXPC incorporate by reference the entire Energy In Depth article as part of its comments.

II. The Industry's Recent Past is Not Its Prologue – Therefore EPA's Proposed Regulations are Not Justified

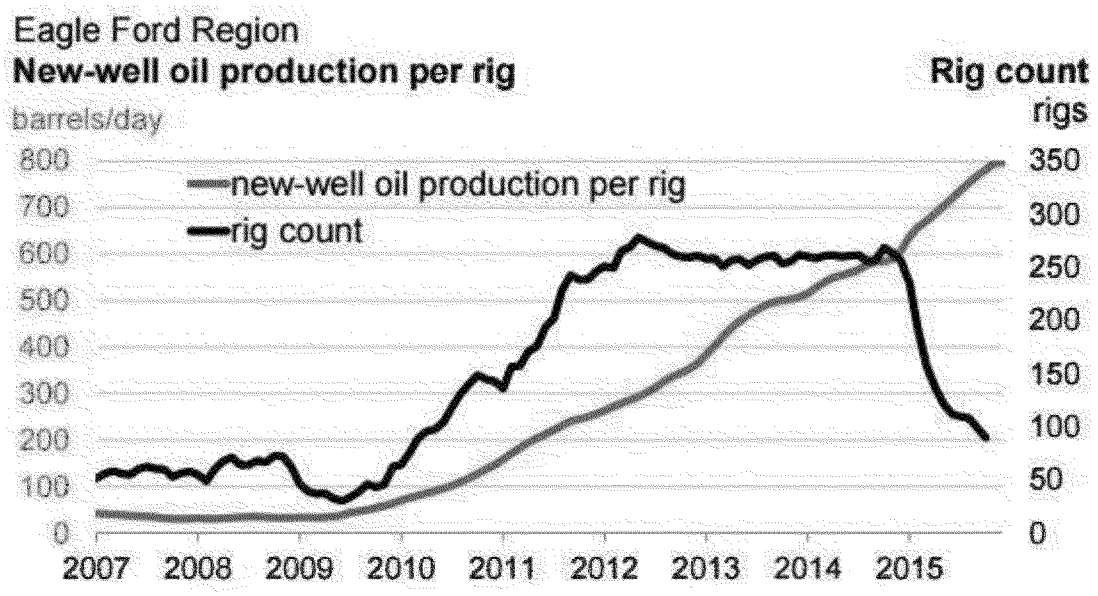
EPA justifies its proposed regulations in large part on the last 10 years of growth in the American oil and natural gas industry – perhaps the most dynamic and rapid growth period in the history of the industry:

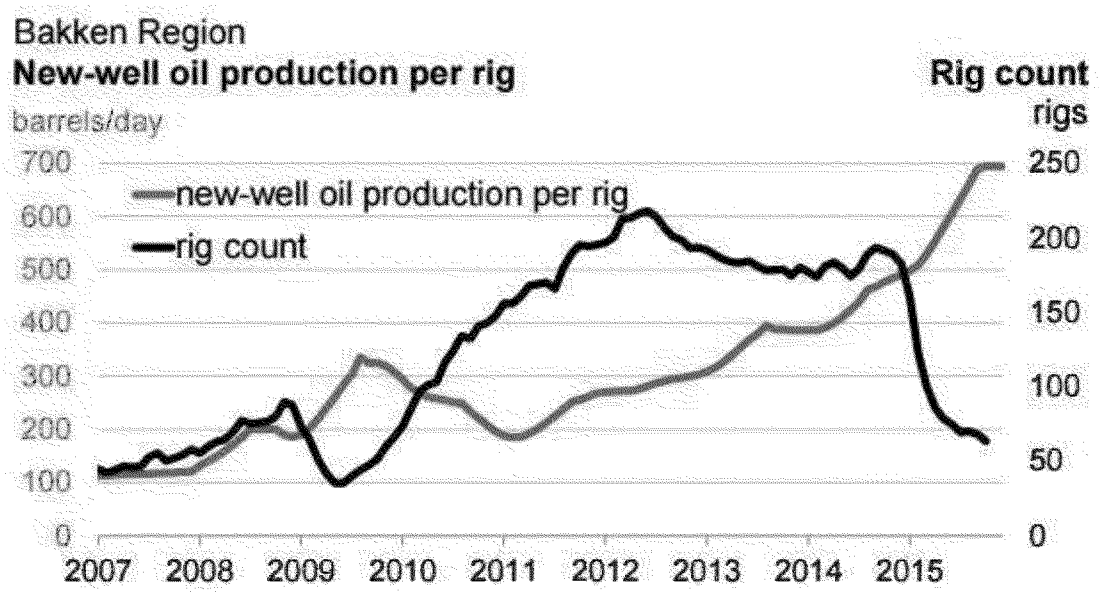
> The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook."[11]

As much as the oil and natural gas sector would like to see that growth rate continue to 2025, it simply will not happen, and the past few years illustrate the cyclical nature of the industry. The price of oil and natural gas has plummeted unlike EPA's hypothetical projections. Operators react quickly to market forces and in many shale plays very few wells are being drilled. For many small, independent operators in various plays, they have not drilled a well in 3 or more years – yet EPA is justifying the cost of the proposed regulations on the most rapid expansion in the history of the industry. The following charts from a recent article by Energy In Depth,[12] based on EIA data, clearly illustrate the impact of market forces:

[11] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015) at 3-9.

[12] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.





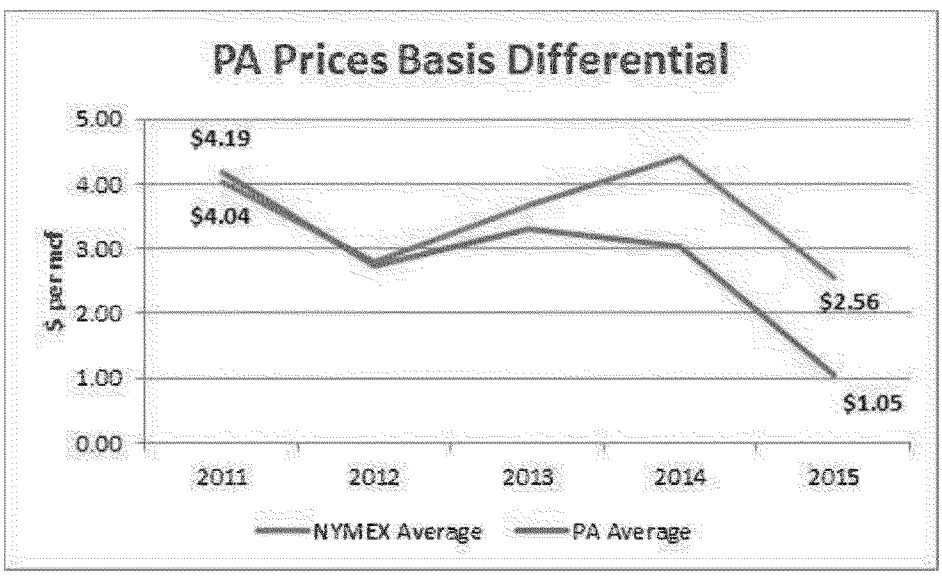
SOURCE: U.S. Energy Information Administration

EPA's cost-effectiveness analysis of the proposed regulations "applies the monetary value of the saved natural gas as an offset to the" cost of the proposed controls.[13] EPA then valued 1,000 standard cubic feet (Mcf) of natural gas at $4.00 for the RIA/cost-effectiveness analysis. The $4/Mcf assumption was based on EIA's 2014 Annual Energy Outlook forecasted

[13] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,617(Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

wellhead prices for the lower 48 states in 2020 ($4.46) and in 2025 ($5.06). EPA considered the $4/Mcf to be "conservative"[14] – presumably because of the predicted value of natural gas in 2020 and 2025. There are numerous problems with EPA assumptions. First, the New York Mercantile Exchange (NYMEX) settlement price for natural gas in October 2015 was $2.56 – 36% lower than EPA's assumed value. EPA has repeatedly indicated that it will finalize the proposed methane NSPS by the summer of 2016, and no financial institution is predicting a dramatic increase in natural gas prices between now and then. For those subject to regulations that come into effect within the next year, EPA's "conservative" estimate of $4/Mcf based on government estimates of what natural gas will cost in 2020 and 2025 is meaningless. IPAA/AXPC appreciates that the "benefit" or value of the natural gas saved by the proposed regulations occurs over the life of the well; however, the emissions from any well are heavily "front-loaded" – with the greatest production, and thus potential emissions, occurring the first few years of the well's life – long before 2020 or 2025. Smaller independents, many conventional well operators, and operators of wells that are marginally economical will not be able to weather the storm until natural gas reaches EPA's conservative value of $4/Mcf. Wells will not be drilled or will be shut in prematurely, and other companies will simply go out of business because of EPA's erroneous assumption on the price of natural gas. EPA's cost-effectiveness analysis for all proposed controls should be based on a price of natural gas that: a) more accurately reflects the price of natural gas when controls will need to be implemented, and b) accounts for the "front loading" of emissions when the price of natural gas is much lower than the $4/Mcf assumed by EPA.

EPA's assumption of $4/Mcf natural gas also fails to acknowledge or account for significant regional differences in the price of natural gas. A review of the wellhead price of natural gas in Pennsylvania provides but one of the many dramatic price variations.



[14] *Id.*

The chart above tracks the PA Price versus NYMEX average prices for the past 4 years and is current through October 2015. The "PA Price" is based on a weighted average of the Dominion South, Leidy, and Tennessee Zone 4 prices reported by Platt's *Inside FERC*. The separation of prices in Pennsylvania from the national index price is driven in large part by the lack of takeaway pipeline capacity and sheer volume of natural gas. The regional variation in price is not accounted for in EPA's cost-effectiveness analysis. Consequently EPA's inflated valuation of the price of natural gas will disproportionally impact certain regions of the country where local or regional factors result in prices that are significantly lower than the national average. EPA's cost-effectiveness analysis must take such significant regional price fluctuations into consideration when evaluating control options.

EPA is proposing regulations so fast that even it cannot keep up with the changing assumptions. Part of EPA's assumption of $4/Mcf natural gas was based on EPA's proposed Clean Power Plan.[15] However, EPA's final Clean Power Plan changed its "assumptions," and EPA now "believes" renewables will play a greater role in the country's future energy mix and natural gas prices may not reach $4/Mcf until after 2030 – well beyond the EPA's analysis for the proposed methane NSPS which ends in 2025. As Energy In Depth points out, the changing assumptions have a dramatic impact on the industry:

> According to EPA data compiled by the American Wind Energy Association (AWEA), a heavier reliance on renewables could result in natural gas prices that are at least 12 percent lower than what would be expected under EPA's base case projection [for the Clean Power Plan]. EPA also acknowledges in its RIA that a $1/Mcf change in price of natural gas translates to as much as a $19 million difference in its cost estimate. In other words, if natural gas prices averaged $3/Mcf instead of $4/Mcf, EPA could be overestimating revenue by roughly 24 percent. Based on the current 2012-2015 average natural gas spot price of $3.44/Mcf, EPA would be overestimating revenue by about $10.6 million. Under the "high renewables" scenario in the Clean Power Plan, which would depress natural gas prices even further, EPA's overestimate would be even higher.
>
> The additional costs could be devastating for an industry already suffering from a market downturn in commodity prices. An analysis by Oppenheimer & Co., for example, already found that EPA's methane rule could wipe out smaller drillers across the United States.[16]

In addition to failing to account for the changed assumptions for the price of oil and natural gas as a result of the Clean Power Plan, EPA has made no effort to account for the impact associated with proposed Ozone NAAQS. For EPA to evaluate the proposed impact of the proposed methane NSPS in a vacuum, ignoring its own significant regulatory initiatives that will have serious impacts on the price of oil and natural gas, as well as the number of entities that will be

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[15] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.

[16] *Id.*

subject to controls, is arbitrary and capricious. Every mutual fund and investment opportunity contains the standard disclaimer along the lines of – "past performance cannot guarantee future results." The oil and natural gas industry is no different – even without EPA impacting market forces with multiple regulatory disruptions.

III. Now is Not the Time to Introduce a New Model to Justify EPA's Proposed Rules.

The benefits of the proposed rule are estimated using the social cost of methane (SC-CH_4), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). However, unlike the USG's SCC which has undergone formal public comment and review, EPA's selected value for SC-CH_4 in this proposed rulemaking is arbitrarily taken from one scientific report[17] that attempts to find an equivalent SC-CH_4 from the SCC, and for which EPA only requested a "peer review" not formal public review and comment. The "peer review" was only concluded in 2014 and discussed as the basis for EPA's cost-effectiveness analysis for the first time in the RIA.[18] The model has not been evaluated by Office of Management and Budget. Providing industry a mere 60 days (plus 17) to evaluate and comment on what amounts to "new math" is inadequate. Also, the selected value of SC-CH_4 used for the Benefit-Cost Analysis in the RIA is based on an arbitrarily selected discount rate of 3 percent, which also was not proposed for public review and comment before being used to justify this proposed rulemaking.[19] Even though now EPA belatedly "seeks comments on the use of these directly modeled estimates, from the peer reviewed literature, for the social cost of non-CO_2 GHGs . . .,"[20] such a request, after EPA has already used its arbitrary value for SC-CH_4 to justify methane emissions controls on numerous methane emissions sources, is arbitrary and capricious. The only proper and legal way for EPA to apply a SC-CH_4 value to methane emissions reductions for proposed rulemakings is to publish a proposal for a SC-CH_4 value (based on scientific evidence and its arguments for a certain discount rate), take public comments on that proposed value, and finalize the value for future rulemakings. Otherwise, EPA can arbitrarily use one value of SC-CH_4 to justify controls on methane emissions from one industrial sector source and then turn-around later and use some other arbitrary value for another industrial sector source, all presumably justified by taking comment on the arbitrary value already used to justify the proposed regulations.

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[17] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,655 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[18] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015).

[19] Exacerbating the arbitrary nature of the 3% discount rate for benefits, EPA inconsistently and inappropriately selected a 7% discount rate for the cost to industry. EPA's unjustified use of different discount rates arbitrarily and capriciously overstates the benefits compared to the costs.

[20] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,656 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

IV. Overarching Comments Particular to the Proposed NSPS for Methane, Subpart OOOOa.

In Sections V and VI of the preamble to the proposed NSPS, EPA dedicates considerable verbiage attempting to justify the need and its legal authority to regulate methane from sources in the oil and natural gas sector. IPAA/AXPC disagrees with both the need and EPA's authority to regulate methane for the reasons set forth below.

EPA's interest in regulating methane is clearly a political decision rather than an environmentally driven decision. Its genesis can be easily seen in the strident demands from anti-fossil energy groups with agendas not to manage industrial emissions but to prevent the development of oil and natural gas. Groups like the Sierra Club have policies that are clear:

> There are no "clean" fossil fuels. The Sierra Club is committed to eliminating the use of fossil fuels, including coal, natural gas and oil, as soon as possible . . . Methane released via extraction and transport is 86 times more potent as a greenhouse gas than CO_2 over a 20-year time frame. The climate-disruption impacts from methane and carbon dioxide emitted by extraction, transport and burning clearly point to the urgent need of keeping fossil fuels in the ground.[21]

This group, along with others, made their demands known to the EPA in multiple meetings and letters, including a December 2013 letter stating the following:

> We commend EPA for updating its VOCs performance standards for this industry in 2012, but the job is far from finished. While some reductions in methane emissions will be achieved as a co-benefit of these 2012 rules, many emission sources are not adequately addressed, such as the vast network of equipment that was installed before those rules went into effect. EPA needs to take immediate steps to produce regulations to directly reduce methane pollution from new and existing equipment from this industry.[22]

Once demanded, the issue of direct methane regulation became the pivot point for development of the current regulatory proposals. As discussed below, the drive for direct methane regulations for the oil and natural gas sector is driven by atmospherics and philosophy, not science or increased environmental benefit.

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[21] *Sierra Club to Big Oil: There are no 'clean' fossil fuels*. Sierra Club (Apr. 21, 2015) *available at* http://angeles.sierraclub.org/news/blog/2015/04/sierra_club_big_oil_there_are_no_clean_fossil_fuels.

[22] Earthworks, *et al*. Interior Secretary Jewell, EPA Administrator McCarty to Curb Methane Emissions from Oil and Gas Industry, Earthworks (Dec. 5, 2013) *available at* https://www.earthworksaction.org/library/detail/open_letter_to_interior_secretary_jewell_epa_administrator_mccarthy_to_curb#.VmHY97Eo74Y.

In reality, EPA was forced to propose regulations to satisfy a political agenda that is governed more by what "we [EPA] believe that the industry can bear . . . and survive."[23] EPA's decision to promulgate methane standards from the exploration and production segment of the oil and natural gas sector is arbitrary and capricious. EPA states that it "believe[s] it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category . . . ."[24] Yet in the very same sentence EPA admits "that the best system of emission reductions (BSER) for methane for all these sources is the same as the BSER for VOC."[25] EPA continues that the BSER for the previously unregulated sources is the same for VOCs and methane. Simply put, the controls on the targeted emissions sources to reduce VOCs are the same as the controls to reduce methane – no more, no less. The "gain" – according to EPA – of adding yet another Subpart of regulations to the already extensive 40 C.F.R Part 60 is "consistency." What EPA chooses to ignore in its preamble discussion is the inevitable "loss" or cost to the industry associated with the regulation of existing sources under Section 111(d).

EPA is silent as to its "beliefs" on whether the industry can "survive" the cost and burden of regulation of existing sources under Section 111(d). This silence is notable and troubling. Clearly, since EPA demonstrates that the technologies used to regulate methane emissions are identical to those for VOC emissions, EPA's choice to expand its regulations to directly regulate methane can only be interpreted as opening a potential pathway to Section 111(d) regulations as the anti-fossil energy organizations demanded. And, while EPA fails to even mention Section 111(d), it must certainly know – based on the demand that existing methane sources must be regulated – that it will face efforts to force such regulation. EPA will surely respond that it will conduct the necessary cost-benefit analysis when it is "forced" to promulgate existing source standards under Section 111(d). Without debating the legalities as to EPA's duties under Section 111(d), this Administration has demonstrated time and time again its propensity to feign resistance to non-governmental organizations' (NGO) "demands" and enter into consent decrees with unreasonable short time periods to promulgate regulations. The irony is that EPA's rationale assumes that the underlying Section 111(b) regulations were necessary in the first place. What has the environment gained (above the benefits gained from VOCs) from regulating methane emissions from exploration and production directly? Nothing. EPA has admitted it. The controls are the same – equally efficient at controlling VOCs and methane. The cost? EPA relies heavily on its original cost-effectiveness analysis for the Subpart OOOO VOC regulations finalized in 2012 and engages in additional analysis discussed in Section VIII of the preamble, concluding that the proposed controls "for methane" are also cost-effective. But nowhere does EPA take into account the cost to the industry associated with the regulations that will likely be forced upon existing sources in this source category. Despite all of the complicated calculations and analyses, the simple fact remains that the controls for VOCs and methane from the targeted sources are the same. There is no demonstrated "need" or unique benefit associated with an additional set of standards specifically for methane. The true cost of the proposed methane

[23] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

[24] *Id.* at 56,595.

[25] *Id.*

regulations is incomplete and unknown without considering the cost associated with regulating existing sources under Section 111(d).

"Consistency across the category" is an insufficient justification. Historically, EPA has tailored new source performance standards to subcategories or segments within a larger, overarching category. One needs to look no farther than Subpart D and its progeny for Steam Generating Units or Subpart E for Municipal Waste Combustors. EPA has shown it can be very creative in tailoring requirements to subcategories or segments within a listed category. Since the Administration first hinted at regulating methane directly from the exploration and production segment, IPAA/AXPC has advocated that such direct regulation was unnecessary, as the controls for VOCs were exactly the same as for methane. EPA acknowledged as much in Section VII in the preamble and stated "[w]e anticipate that these stakeholders will express their views during the comment period."[26] IPAA/AXPC questions the appropriateness of EPA's decision to essentially ignore a central premise of two federal trade associations that represent approximately 54% of oil and 85% of natural gas exploration and production capacity of this country. Is it appropriate for IPAA/AXPC to guess as to EPA's reasoning and justification? Much of EPA's 67-page preamble is dedicated to justifying its legal basis for regulating methane directly and the cost-effectiveness of the proposed controls. It fails to address in any meaningful way why it is necessary or justified to promulgate methane standards from the exploration and production segment. EPA's justification boils down to: 1) EPA assumes it is has the legal authority to do so; 2) EPA has placed a high value on "consistency" within the source category; and 3) EPA "believes" the industry can "survive." EPA is on much stronger legal footing addressing segments or subcategories differently within the oil and natural gas sector than asserting it does not need a separate endangerment finding for methane. EPA's insistence, without explanation, on promulgating methane standards for exploration and production sources, when the controls are exactly the same, needlessly increases the regulatory burden on everyone – the regulated and the regulator. IPAA/AXPC should not have to guess until the rule is finalized and potentially litigate an issue that has been clearly articulated to EPA, the Small Business Administration, and the Office of Management and Budget long before the rule was even proposed.

In Section V and VI, EPA indicates it is responding to and granting a Petition for Reconsideration associated with the 2012 NSPS Subpart OOOO for VOCs which requested the promulgation of NSPS for methane. The key elements outlined as EPA's reasoning for granting reconsideration are:

- "the wealth of additional information now available to us . . ."[27]
- "[t]he oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide."[28]

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[26] *Id.* at 56,609.

[27] *Id.* at 56,599.

[28] *Id.*

- "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources."[29]
- "a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare for current and future generations."[30]

EPA then dedicates approximately 10 pages of the preamble to defending their position that a separate endangerment finding strictly for methane is not needed (and backfilling in case they are wrong), making the case for global climate change from GHGs, and presenting various charts on U.S. methane emissions. Unlike the remaining sections of the preamble (approximately 55 pages), in which EPA seeks specific comments on particular issues at least 50 different times, EPA did not seek comment once in Sections V and VI.

While IPAA/AXPC has not attempted to take issue with or refute every inaccuracy or assertion contained within these sections of the preamble, EPA's key elements are addressed briefly below:

- IPAA/AXPC agrees there is a wealth of additional information – much of it taking issue with anthropogenic global warming. A cursory review of the website Watts Up With That, http://wattsupwiththat.com/, reveals the science is not "settled" as EPA would have one believe.
- While EPA alleges that the oil and natural gas sector is one of the "largest emitters of methane", EPA's own numbers illustrate that in 2013, the oil and natural gas sector accounted for 2.22% of the Total U.S. GHG Inventory.[31] And as stated earlier, the exploration and production segment is only 1.07% of that 2.22%. The oft-quoted greenhouse gas multiplier is subject to manipulation based on the timeframe used to make the carbon dioxide comparison, and the "legacy warming from fugitive methane is minuscule compared to that of carbon dioxide."[32]
- The adequacy of EPA's endangerment finding is far from settled and will certainly be subject to legal challenge upon final promulgation of this rule if EPA persists with its intention to regulate methane directly.[33]
- In supporting its claim that EPA better understands climate change, it cites the Intergovernmental Panel on Climate Change's (IPCC) 2013-2014 Fifth Assessment Report (AR5). Many of these "citations" or statements to support EPA's position are

[29] *Id.* at 56,601.

[30] *Id.* at 56602.

[31] *Id.* at 56,608.

[32] Elizabeth A. Muller and Richard A. Muller, *The Facts About Fugitive Methane*, Centre for Policy Studies (Oct. 2015) *available at* http://www.cps.org.uk/files/reports/original/151022155129-TheFactsofFugitiveMethane.pdf.

[33] David Yaussy and Elizabeth Turgeon. *Unringing the Bell: Time for EPA to Reconsider Its Greenhouse Gas Endangerment Finding*, 116 W.Va. L. Rev. 1007 (2014).

from the Summary for Policy Makers, which was written by the policy makers, not the scientists who authored the report.[34] Judith Curry, former Chair of the School of Earth and Atmospheric Sciences at the Georgia Institute of Technology, evaluated and commented on the AR5, not the Summary for Policy Makers, and noted various factors that evidence a weakening of the case for anthropogenic global warming:

- Lack of warming since 1998 and growing discrepancies with climate model projections
- Evidence of decreased climate sensitivity to increases in CO_2
- Evidence that sea level rise from 1920-1950 is of the same magnitude in 1993-2012
- Increasing Antarctic sea ice extent
- Low confidence in attributing extreme weather events to anthropogenic global warming.[35]

- EPA also relies heavily on the U.S. Global Change Research Program's (USGCRP) 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), to support its alleged climate change impacts – ranging from decreased Artic summer sea ice to increased sea levels to drier/more intense storms, as well as greater impact to children and the elderly.
  - Studies not cited by EPA demonstrate no significant changes or deviations from cyclical patterns in the quantity of ice.[36]
  - As to the frequency and intensity of storms, other studies not cited by EPA raise questions regarding storm predictability: "October marks a continuation of a record-long major hurricane (Category 3 or stronger) landfall drought in the United States. The last major hurricane to make landfall in the U.S. was Wilma on October 24, 2005. This major hurricane drought surpassed the length of the eight-years from 1861-1868 when no major hurricane struck the United States' coast. On average, a major hurricane makes landfall in the U.S. about once every three years. The reliable record of landfalling hurricanes in the U.S. dates back to 1851."[37] "The bar [see footnote] charts

[34] Wim Rost, *IPCC ≠ Science ↔ IPCC = Government*, Watts Up With That (Nov. 29, 2015) *available at* http://wattsupwiththat.com/2015/11/29/ipcc-science-ipcc-government/.

[35] Judith Curry, *IPCC AR5 Weakens the Case for AGW*, Climate Etc. (Jan 6, 2014) *available at* http://judithcurry.com/2014/01/06/ipcc-ar5-weakens-the-case-for-agw/.

[36] http://ocean.dmi.dk/arctic/plots/icecover/icecover_current_new.png; http://nsidc.org/data/seaice_index/images/daily_images/S_stddev_timeseries.png

[37] National Oceanic and Atmospheric Administration , National Centers for Environmental Information, State of the Climate: Hurricanes and Tropical Storms for October 2015 (Nov. 2015) *available at* https://www.ncdc.noaa.gov/sotc/tropical-cyclones/201510. While other ranking metrics for hurricane's are being developed, the National Hurricane Center for the National Oceanic and Atmospheric Administration and EPA continue to regularly rely on an cite to the Saffir-Simpson Hurricane Wind Scale to compare the potential impacts of hurricanes.

> below indicate there has been little trend in the frequency of the stronger tornadoes over the past 55 years."[38]

The title of Section V of the preamble is "Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?" EPA's stated concerns are ostensibly laudable. However, nothing set forth in Section V or Section VI of the preamble justifies or necessitates separate methane NSPS from the exploration and production sector.

A. Consistent with the Clean Air Act, State Programs Should Control

The CAA is structured such that states should have primacy and be primarily responsible for compliance with the requirements of the Act. Many of the states with the most active shale plays have implemented state regulations to address many of the emissions sources targeted in the proposed Subpart OOOOa regulations. States with state permitting programs and/or State Implementation Plans (SIPs) that contain limits on sources that are legally and practically enforceable should be deemed sufficient for overlapping and duplicative requirements in Subpart OOOO and the finalized version of Subpart OOOOa. EPA should defer to existing state regulations to the greatest extent possible to deem compliance with state regulations on the same sources as constituting compliance with the final Subpart OOOOa regulations. Duplication and inconsistency between state and federal regulations simply add to the cost of compliance with little to no additional benefit to the environment. To the extent EPA does not allow for such provisions, EPA should demonstrate that the duplicate or "more stringent" regulations that EPA is promulgating are incrementally cost-effective: meaning that the cost associated with the duplicative or inconsistent federal control requirement is cost-effective based on the incremental environmental benefit above the state regulation already in place or deem compliance with the state regulations as compliance with Subpart OOOOa. EPA must justify with an *incremental* cost and benefit analysis any proposal to impose additional federal regulations that it deems more stringent than existing state regulations.

B. Fugitive Emissions at Well Sites and Compressor Stations

Managing fugitive emissions or "leaks" from the oil and natural gas sector appeals to common sense. Leaks associated with natural gas operations represent safety concerns, negative impacts to the environment, and are wasteful from an economic standpoint. The industry has relied on audio/visual/olfactory (AVO) inspections for many years, and only recently has the industry focused considerable attention on technological advances to detect leaks. It is an emerging process – both in terms of technology and methodology (regulatory and corporate management). EPA's preamble bears this fact out with the number of specific requests for "comment" on the leak detection aspect of the proposal. IPAA/AXPC supports, in concept, the ability to satisfy the leak detection and repair (LDAR) requirements of the proposal with an appropriate "corporate fugitive monitoring plan," but a 60-day comment period (plus a random 17 days halfway through the comment period) is not enough time to create and implement such a

[38] National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Historical Records and Trends, *available at* https://www.ncdc.noaa.gov/climate-information/extreme-events/us-tornado-climatology/trends.

program. Additionally, recent data and studies demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions.[39]

A handful of states are taking the lead on creating regulatory frameworks, each of which is different, and none of which follows the proposed EPA framework. Experience with the state programs is indicating that correction of fat tail emissions results in effective management of fugitive sources and, once corrected, the need for full-blown inspections/surveys more often than an annual frequency is unjustified. Even the states with the most aggressive LDAR programs are not focused on quantifying the total amount of methane "saved." The very nature of fugitive emissions makes it very difficult to quantify how much gas is being "saved." It is not as simple as a single point source with consistent flow where one can easily measure the emissions before and after controls are "bolted on" a stack or emission point. The component count at most facilities is likely in the hundreds to thousands, with only a very small percentage of the components leaking. For those that are leaking, the quantity of gas leaking varies considerably. Nonetheless, EPA crunched some numbers in a hypothetical world and assigned some value to the natural gas that is saved. In reality, very few companies will realize any change in the sales meter pre- and post-LDAR. The savings are largely illusionary to the average operator. The value of the natural gas "saved" through the LDAR programs is highly speculative. In addition, EPA did not account for the size of the facility when estimating the percent savings. EPA's percentage saved calculations are based on Colorado's regulations and related data. Colorado's 80% reduction, which EPA adopts, is based on monthly inspections for facilities with less than 50 tons per year. EPA assumes, with no additional support, that their proposed regulations can achieve an 80% reduction from quarterly inspections for all facilities, regardless of size. IPAA/AXPC questions the validity of EPA's cost-effectiveness analysis for its proposed LDAR regulations.

EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements. This performance-based approach would be the most effective and efficient.

Other than the handful of companies that provide the optical gas imaging (OGI) technology, industry is united in its position that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be

[39] David T. Allen, *et al.* Measurements of methane emissions at natural gas production sites in the United States, Proceedings of the National Academy of Sciences of the United States of America (Aug. 19, 2013) *available at* http://www.pnas.org/content/110/44/17768.

met – not dictating a particular technology. Dictating a particular technology stifles innovation. There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas lead detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology.

OGI/forward looking infrared (FLIR) technology suffers from numerous limitations. Perhaps most importantly, it is not inherently safe – if not used properly on site, it could cause an explosion. Additionally, the results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. These problems are exacerbated in windy and/or cold conditions that are prevalent in a number of the shale plays. The technology is prohibitively expensive to smaller operators, and there is a limited supply of qualified service providers that can afford the camera. Even for the larger companies, at approximately $120,000 a camera, there will be a limited supply. For companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require survey pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, the OGI technology is not a quantitative tool – it is not capable of determining how much natural gas is leaking.

As discussed above, a number of states are taking the lead on LDAR programs and are learning how to effectively and efficiently implement controls and administer surveys. Despite repeated requests by IPAA during the Small Business Advocacy Review Panel process and other trade association requests for EPA's proposal to be consistent with and not duplicative of existing state LDAR programs, EPA's proposal runs roughshod over existing state programs. Inconsistencies and duplication in the proposed regulations and existing programs are burdensome, inefficient and costly – especially to small entities and independent operators. IPAA/AXPC specifically incorporates by reference the comments on the NSPS proposal of Anadarko which highlight the inconsistencies between the proposed Subpart OOOOa and existing regulations in Colorado and Pennsylvania. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy. States with existing programs should be deemed sufficient, and compliance with the state program should be deemed as compliance with the finalized federal program. This is not a new concept in the context of EPA's NSPS for the oil and natural gas industry, and EPA should revise the proposed regulations to model the exemption for storage vessels in Subpart OOOO and deem legally and practically enforceable state LDAR programs to suffice for the proposed federal regulations. Such revisions would greatly reduce the regulatory burden for sources located in states that have proactively addressed fugitive emissions from the oil and gas sector. To the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint.

Additionally, consistent with the CAA, the state programs should control, and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Another issue advocated by IPAA/AXPC and/or member companies prior to publication of the proposed rule was to *not* base LDAR requirements on arbitrary component count or percentage of components leaking at a given site – yet that is exactly what EPA proposed. EPA suggests that its proposal, which bases the frequency of surveys on the percentage of leaking components, provides an "incentive" for companies to be more vigilant in their identification and repair of leaks. As discussed above, the incentive to identify and repair leaks already exists, as there is a strong safety and economic incentive. EPA's proposal based on percentage of leaking components creates a recordkeeping nightmare. The regulations are less than clear as to what constitutes a "facility" in terms of where to draw the line and stop the component count. As a result of the ambiguity in the proposal, it is difficult to evaluate if EPA's assumptions on components per well count are accurate. There is tremendous variability in the number of wells and types of equipment on well sites. For EPA to base its cost effectiveness on a "model well pad" is problematic. Member companies report component counts in the hundreds to thousands of components. Such a wide range is in part, a function of lack of clarity in the regulations and also calls into question the accuracy of EPA cost-effectiveness assumptions on a model plant. If EPA persists with a percent-leaking methodology, the regulations need to be clarified on what components are to be counted and how to define the limits of the facility for the component count. EPA's own evaluation concluded that quarterly surveys of the intensity proposed are not cost-effective. Yet, if more than 3% of the components are leaking, the proposed regulations require quarterly surveys. If quarterly surveys are not cost-effective, having more than 3% of the components leaking does not somehow make the quarterly surveys become cost-effective. Additionally, there is no direct correlation between the number of leaking components and quantity of emissions, so basing the frequency on the percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions. While there is no direct correlation between the number of components and quantity of emissions, the component count/percent leaking ratio directly impacts the recording keeping requirements – again with no demonstrated reduction in emissions. It is just more paperwork compliance for operators.

Furthermore, leaks are often related to some sort of malfunction and once fixed, stay fixed such that there is no need or rational basis to increase the survey frequency. As EPA discussed in the preamble, experience with the state programs demonstrates there are "gross emitters" or "super emitters" that represent a very large percentage of the overall fugitive emissions profile (consistent with the fat tail issues discussed above). Preliminary information from companies with operations in states with aggressive LDAR programs already in place indicates treating every component "equally" is an inefficient use of limited resources. This information suggests that components subjected to constant or frequent vibration (such as components associated with a compressor) are much more likely to have leaks than say, threaded connections. And in terms of total component count at a given facility, there are likely to be many more threaded connections than the components most likely to leak at the relatively few compressors. Even if it is difficult to predict "gross emitters" or "super emitters" at any given

facility, the knowledge gained from sources within states with existing LDAR programs suggests that treating all components equally and basing the frequency of surveys on leaking component percentages is inefficient from an emissions reduction perspective and extremely burdensome and costly – especially to small entities. Again, more time to craft a regulatory program designed to identify and repair gross emitters would be preferred by IPAA/AXPC.

Basing the frequency of surveys on the percent of components leaking exemplifies that EPA is largely guessing at what constitutes an appropriate LDAR program. EPA should not rush to judgment and instead learn from the state programs to determine the most effective and efficient way to reduce leaks. Alternatives include a performance-based approach such as that in Wyoming, basing the survey frequency on the size of the facility or the quantity of emissions leaked or perhaps a combination of a more technology-based annual survey with periodic AVO "inspections" between annual surveys. If EPA persists with the percentage-leaking-component approach, flexibility should be built into the program that companies could commit to semi-annual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. For some companies, the ability to plan for semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. However, for some smaller entities or independent operators, the ability to reduce surveys to an annual basis might be beneficial. Sources should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances. Further, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. As some states have done, EPA should more clearly define and exclude components that are designed to release pressure for safety reasons, e.g., thief hatches and enardo valves.

Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period – especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days, respectively. If EPA persists with the unrealistic time frames, a mechanism allowing for a "variance" on the time frames when certain circumstances exist should be built into the regulations. Even with companies with the resources to purchase a camera, their operations may be geographically dispersed or weather conditions are uncooperative such that they cannot realistically get from one location to the other. Smaller entities and some independent operators who cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

EPA's cost-effectiveness for the proposed LDAR program requirements is fundamentally flawed because it merely looks at the cost of conducting the survey and fails to accurately

account for the increased record-keeping and reporting requirements. EPA's analysis is myopically focused on a straight up comparison of "cost-effectiveness" for semi-annual surveys versus annual and opts for semi-annual requirements because the relative cost-effectiveness is the same: $2,475 for annual versus $2,768 for annual under the single pollutant approach at the well site.[40] EPA conducted similar comparisons for the multi-pollutant approach at the well site (as well as both comparisons at a compressor station).[41] In every instance the annual survey was more cost-effective but EPA selected the semi-annual surveying because the cost/ton removed was similar. There are two problems with that philosophy. First – in selecting the semi-annual requirement, EPA basically double the cost of the requirement to industry. Second, the theoretical or modeled additional reduction in emissions is a very small percentage of the overall emission reductions associated with the proposed regulations. The additional cost associated with the annual survey requirement is substantial while the increased benefit to the environment is minimal. The additional regulatory burden will be disproportionately felt by small entities. The proposed LDAR requirements basically require all companies, regardless of size, to implement costly information systems to track and monitor compliance. For example, one of the larger, more sophisticated operators with a data management system already in place incurred an additional $10,000 in external costs associated with developing new or revised software, and an additional $37,000 associated with internal set-up costs and employee time focused on implementation. These costs were associated with complying with Colorado's LDAR program in a small gas field of 174 wells and, as indicated, were in addition to an existing management system at an estimated cost of $80,000 annually. It does not appear that costs such as these were considered in EPA's cost-effectiveness analysis. EPA's proposed requirements appear to be based on what is required at natural gas plants, and expanding that level of detail to remote, un-manned production sites is inappropriate. Such level of detail is not warranted nor has the cost been adequately justified – especially over the life of the well. The majority of the "benefit" associated with the surveying is on the initial startup of a well (or startup after modifications). It is impossible to calculate an accurate annual gas recovery rate over the life of a well site.

The new record-keeping requirements associated with the LDAR are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record-keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency. EPA requested comment on "ways to minimize recordkeeping and reporting burden." As discussed above, EPA should evaluate existing state requirements and liberally deem them sufficient for purposes of Subpart OOOOa and establish a mechanism for states to implement their own programs that supersede and satisfy Subpart OOOOa.

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[40] Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities – Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2015) (hereinafter, TSD), at Table 5-14.

[41] *Id.* at Tables 5-15, 5-17, 5-18.

IPAA/AXPC supports the limited exclusions from the LDAR requirements that EPA has proposed but requests certain clarifications and expansion of the exclusions. Excluding low production well sites – defined as the "average combined oil and natural gas production for the oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production"[42] -- is extremely helpful for small entities and smaller independent operators. IPAA/AXPC understands the 15 boe is also an "off ramp" – that is, when a well drops below 15 boe, it is no longer subject to the LDAR requirements. IPAA/AXPC requests the regulatory language be revised to indicate that when a well drops below 15 boe, based on a 30-day average production, the LDAR requirements no longer apply. EPA should provide an additional exclusion for well sites with component counts below EPA's model well site: below 548 components for gas well sites and below 135 components for oil well sites should be excluded from the LDAR requirements.[43] EPA concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts and therefore those well sites should be excluded. Such exclusion would help all producers but would have greatest benefit to small entities that are likely to have smaller well sites. IPAA/AXPC also supports EPA's proposed exclusion for well sites with extremely dry gas where only the wellhead exists and there is no "ancillary equipment." IPAA/AXPC requests clarification that a meter and drip present at the well site do not constitute "ancillary equipment." Finally, in response to an EPA request for comment, IPAA/AXPC suggests that the LDAR requirements should only apply to those components that are directly connected to the fractured, refractured, or added well and should not apply to tank batteries or other equipment off the well pad which may receive fluids from the fractured, refractured or added well.

C. Oil Well Reduced Emission Completions

As with the proposed LDAR requirements, in its rush to promulgate regulations aimed at additional sources of VOCs and methane, EPA assumed that reduced emission completions (RECs) on oil wells are essentially the "same" as RECs on natural gas wells. Unlike a natural gas well, where the price of natural gas dictates many operational decisions, the economic driver for oil wells is the price and volume of oil – not natural gas. When EPA promulgated Subpart OOOO regulations for VOCs and RECs on natural gas wells, EPA indicated it did not have enough information to determine if oil well RECs were cost-effective.[44] The cost-effectiveness of oil well RECs was also raised by EPA in the Methane "White Papers" released on April 15, 2014.[45] IPAA/AXPC and individual member companies submitted comments on EPA's oil well

[42] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,612 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[43] TSD at Table 25-1.

[44] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 ,49516 (Aug. 16, 2012)

[45] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production* (Apr. 2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.

REC White Paper - identifying concerns with the cost-effectiveness of RECs for oil wells.[46] EPA's preamble discussion in Section VII of the proposed standards for oil well RECs makes a general reference to the Technical Support Document (TSD) for the current proposal in terms of justifying its best system of emissions reduction determination, but there is no updated cost/benefit data cited in the proposal. The citations refer back to the "2012 NSPS evaluation." It appears EPA has failed to cite any new or additional information collected since the 2012 evaluation to support the cost-effectiveness of the proposed oil well REC requirements. The economics of natural gas RECs are different and do not support oil well REC requirements.

Based on the preamble discussion of undertaking of an oil well REC, EPA assumes the process is essentially the same, but this is not necessarily the case. While certain wells will have relatively clear initial and separation flowback stages like natural gas wells, there are instances where there is no separation flowback stage owing to the lack of gas or quality of gas such that operation of a separator is not feasible. On certain wells, the initial flowback stage is followed by directing the flowback immediately into the production battery. Perhaps more so than with RECs on natural gas wells, the various stages of flowback on oil wells can be difficult to clearly delineate, and the ability to utilize a separator is a function of engineering judgment. IPAA/AXPC supports the concept of identifying two stages of flowback, with no control placed on the associated gas with oil well completions during the initial flowback stage. However, there will be situations where certain oil well completions will not experience a separation flowback stage.

In the preamble discussion of the REC requirements for both subcategory 1 and subcategory 2 wells, EPA expressed a clear intention to allow for venting of emissions in lieu of combustion during periods when the flowback gas is noncombustible.[47] This intent is particularly important for completions utilizing inert gas, such as nitrogen or nitrogen foam, instead of water as the medium for the fracturing process. The inert gases present in the flowback make the gas, for a period of time, "not of salable quality" and technically infeasible. The relevant provisions of the proposed regulations at 40 C.F.R. 60.5375a(a)(3) and 40 C.F.R. 60.5375a(f)(2) should be modified at the end of the provision to allow for venting when "*it is technically infeasible due to inert gas concentration.*" The addition of this phrase at the end of the current proposed language would eliminate any ambiguity as to EPA's intent.

IPAA/AXPC agrees that the feasibility of oil RECs should take into consideration the availability of gathering lines and that it is not as simple as a linear distance from a gathering line. As EPA acknowledges in the preamble, there are many factors that determine gathering line availability – not just distance. There are other considerations that drive the decision to recover gas which include, but are not limited to, the following factors: gas volume, gas pressure, gas Btu content, gas liquid content, sales line gas pressure requirements, moisture

[46] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

[47] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,630, 56,632 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

requirements, compression, and current takeaway capacity of existing gathering systems. One workable approach that might assist regulators is to use a linear distance, such as a ¼ mile, to presume that flaring is permitted because it is generally agreed that, beyond that distance a gathering line is not available. The converse, a gathering line within a ¼ mile, should not be assumed to be available prompting a case-by-case determination based on the factors detailed above. Again, IPAA/AXPC supports EPA's acknowledgment that the availability of a gathering line must be considered in evaluating the feasibility of an oil well completion but that it is not as simple as designating a linear cut point.

IPAA/AXPC supports the various exclusions from the oil well REC requirements for oil wells less than 15 boe; wells with a gas-to-oil ratio (GOR) of 300 or less; and the low-pressure well. Although not an exact science, operators can make engineering judgments and estimations based on experience in a developed formation. If the well initially exceeds 15 boe, a potential solution is to allow the operator to temporarily shut in the well and bring in REC equipment or limit the production such that the well does not make more than 15 boe for any measurement period as long as the average rate of the averaging period is 15 boe or less. In the event that the operator, based on strong well performance, decides to bring in REC equipment, he could earn a 0 bopd credit to the averaging period for every day the REC is used. IPAA supports the inclusion of an exclusion for a "low-pressure oil well" but it is not appropriate to utilize the definition for a "low-pressure gas well." Oil and water are fairly equivalent on their impact on the intent of this low-well pressure exemption in the early phases of flowback, and the water/oil ratio will change significantly during the early flowback periods for hydraulically fractured wells. The main difference is that, once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher, i.e. more liquids in the tubing, and this factor should be increased. For example a well making 15 boe up 2-3/8" production tubing at a 300 GOR could have a gradient of 5 to 10 times as much. The new record-keeping requirements associated with oil RECs (but also applicable to natural gas RECs) disproportionately impact the smaller, independent operators (conventional operations).

Finally, IPAA/AXPC continues to believe EPA's cost-effectiveness analysis for oil well completions is flawed because it is taking "credit" for well completions industry has already done or will do regardless of regulations. IPAA and WEA filed extensive comments on EPA's oil well completion White Paper on June 16, 2014.[48] The issues raised in that process have not been adequately addressed by EPA in the RIA or Technical Support Document for this rulemaking. The most relevant provisions of those comments are reproduced below:

> Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares at oil wells as operators are already engaged in such

[48] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014). The Comments of AXPC/America's Natural Gas Alliance (ANGA) are incorporated by reference.

> practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared.
>
> See the comments above, as they pertain to EPA's data sources and estimates.
>
> For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds ("VOC") emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a "national estimate" will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance).
>
> . . .
>
> As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms "co-produced" wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being "controlled"—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary.[49]

In the TSD for the proposed Subpart OOOOa, EPA continues to claim ignorance as to the extent state and local regulations require well completions and claim an arbitrarily low assumption that only 7 percent of completions are controlled in the absence of federal regulations.[50] This

[49] *Id.* [internal citations omitted]

[50] TSD at 22.

arbitrarily low assumption skews EPA's cost-effectiveness and takes "credit" for activities the industry is doing on its own.

D. Pneumatic Pumps

IPAA/AXPC's primary concern with the proposed requirements for pneumatic pumps is that EPA has overestimated the ease (and thus the cost) of sending captured gas to an existing combustion device. It is not as simple as plumbing a line from the pump to the control device. The intermittent nature of the gas flow and low pressures can create serious safety and operational difficulties if not appropriately designed along with significantly increasing engineering costs associated with the closed vent system upgrades. The difference between the amount of gas being vented from a storage tank and the amount of gas coming from a pneumatic pump is large, and designing a closed vent system to properly account for this pressure differential would be exceedingly difficult and costly. To meet the needs of both components, the final design would likely have the potential to increase emissions (such as being forced to use a small compressor or being forced to set thief hatches at different pressures that in turn cause more emission events from the tanks) than if the pump was vented directly to the atmosphere. The volume of gas to be captured from pneumatic pumps is relatively small, and when EPA more accurately reflects the cost associated with capturing the gas and routing it to an existing control device, IPAA/AXPC questions whether the proposed controls will be cost-effective. If EPA persists with its proposed controls on pneumatic pumps, it should clarify the definition of an "affected facility" and the interplay with reporting requirements. "Affected facility" should mean only new or modified continuous high-bleed pumps and specifically exclude low-bleed pumps (< 6 scfh). Since low-bleed pumps would not be considered an "affected facility," it is assumed they would not be subject to the reporting requirements for high-bleed pneumatic pumps. IPAA/AXPC requests confirmation of its reading of the reporting requirements.

The applicability of EPA's proposed regulations turns on whether a control device is already present at the site. EPA's regulations and preamble are silent as to whether the existing control device is already subject to NSPS and therefore an affected facility. To the extent the existing combustion device is not an affected facility, Subpart OOOOa should be clarified that existing, non-affected facility combustion devices should not become subject to NSPS simply because a new pneumatic pump is installed or an existing pump is modified. If EPA intends to pull in the existing control device and make it an affected facility, EPA must revise its cost-effective analysis to account for the additional costs associated with "converting" the existing control device to an affected facility.

E. Compressors

IPAA/AXPC supports EPA's indication that the compressor rules promulgated under Subpart OOOO and proposed Subpart OOOOa do not apply to compressors at the wellsite. IPAA/AXPC interprets the proposed CTG for compressors as essentially the same as that proposed in Subpart OOOOa, yet the CTG indicate the regulations would apply to compressors

"between the wellhead and point of custody transfer."[51] This language seems inconsistent with the concept that compressors at the well site are not subject to Subpart OOOO or the proposed Subpart OOOOa. IPAA/AXPC requests clarification. Similarly, IPAA/AXPC requests clarification on whether compressors at well sites are subject to LDAR requirements. Finally, in response to EPA's specific request, IPAA/AXPC suggests the fugitive emissions requirements at compressor stations should apply only to the fugitive sources that are connected to the added or modified compressor.

F. Liquids Unloading

IPAA/AXPC supports EPA's conclusion that it does not have sufficient information to propose standards for liquids unloading. IPAA and WEA filed extensive comments on EPA's liquids unloading White Paper on June 16, 2014.[52] The numerous issues raised by IPAA/WEA have not been adequately addressed and continue to be the basis for IPAA/AXPC's position that controls aimed at reducing emissions from liquids unloading vary greatly based on numerous factors that make it difficult if not impossible to promulgate a cost-effective NSPS. IPAA/AXPC incorporates by reference these comments in their entirety regardless of topic. Nonetheless, certain portions of IPAA/WEA's comments on liquids unloading warrant repeating:

> The industry has a strong economic incentive to minimize venting episodes. Indeed, what EPA views as a pollutant is generally viewed by industry as a salable product and thus industry has an economic incentive to capture as much of the gas as possible. Unfortunately, it is not always possible to unload without venting—sometimes for safety reasons and sometimes for technological reasons. The limitations on the ability to minimize venting are difficult to predict and largely well-specific.
>
> Although the challenges associated with liquids unloading are equally prevalent among horizontal and vertical wells, the ability to recover the cost of "controls" will most likely disproportionately affect smaller operators, marginal wells and vertical wells. Nowhere in the charge questions or White Paper does EPA attempt to address the potential for such disproportionate economic impacts to result from a "one size fits all" approach to minimizing emissions during liquids unloading. The need to unload liquids depends primarily on reservoir pressure, liquid/gas ratio, and surface operating pressure; the most appropriate technology used to unload will depend on the producing formation, site equipment and logistics, and other considerations. There is a wide variety of reservoir properties across and within basins, and flexibility is critical in the continued production of these wells.

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[51] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

[52] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

As a general matter, the national estimates of methane emissions based on EPA's Greenhouse Gas Reporting are overstated, over-reported and dated at this point. The 2012 API/ANGA study included in the White Paper indicates as much and concludes that EPA's Greenhouse Gas Inventory was overestimated by orders of magnitude. More source specific data—i.e., data specifically focused on liquids unloading—is needed before conclusions should be drawn as to this subsector's contribution to methane emissions from the broader oil and natural gas sector.

The formulas used by EPA to calculate the gas volumes vented during unloading events estimates that the entire well column is vented during an event. The reason for the unload is because fluid is sitting in this column, taking up this space, and resulting in an overestimation of emissions. Additionally, the formulas utilize only a casing diameter for wells without plunger lifts (and tubing diameter for wells with a lift). Most wells are generally equipped with production tubing strings in an effort to increase the velocity of the gas and liquids and reduce the potential for liquid [un]loading problems. When these tubing strings are in place, gas volumes vented during unloading events would be from the casing-tubing annulus (area between the outside of the tubing and the inside of the well's casing) and not from the entire volume of the well's casing. This is not accounted for in many of the estimates.

In addition, the formulas used by EPA assume that gas is being vented for any well liquid unload lasting longer than one hour (or 30 minutes for unloads that are plunger lift assisted). During the liquid unloading process, there is usually an initial release of gas followed by a period of time where operators are waiting for the liquid to travel up the well bore and nothing is being released from the well; this can happen for only a few minutes or up to several hours. The formulas assume that any duration longer than one hour is continually venting at a rate equal to the production rate of gas when in fact no gas is being vented, significantly overestimating the emissions from these activities.

Factors influencing regional differences in VOC and methane emissions are a complex set of variables that include temperature, pressure, hydrocarbon composition of the oil and gas within the production formation, gas to liquid ratio, well configuration, well depth and surface conditions at the time of the unloading event. The factors that influence the frequency and duration of liquids unloading include those listed in the previous sentence, and the solution for each well and/or application is based on engineering calculations and judgment and is intrinsically well-specific. Production engineers run models to determine the proper design and operating parameters. The numerous factors and inability to generalize even by formation make it difficult to predict which wells will be more susceptible to high levels of emissions associated with liquids unloading.

The need for liquids unloading is not based on a strict set of parameters or rules. It is based on a complex set of variables—primarily reservoir pressure, but

also including (but not limited to) gas to oil ratio, geologic formation types, and age of well. In addition to geological factors, technology-based factors include (a) large or no production tubing strings installed, (b) wells with high sales line pressure and no compression equipment installed at the surface, and (c) wells not equipped with artificial lift equipment such as gas lift mandrels/valves, plunger lift, rod pump, etc. Regarding the type of well, horizontal or hydraulically fractured wells are no more likely than vertical or non-hydraulically fractured wells to develop liquids [un]loading problems. It is not only a problem for wells further down their decline curve.

Simply put, one cannot generalize—there is no particular pattern or predictable model that would forecast which well types are prone to having liquids [un]loading problems. It is the inability to generalize that makes each well unique and requires a case-by-case analysis to address a liquid [un]loading problem. That said, there are some trends—the highest tendency are deeper wells with high liquid to gas ratios and low bottom hole pressure. Because the reservoir pressure does decline over time, liquid [un]loadings are more prevalent in older wells. Wells drilled and completed in formations drained by previous production may experience [un]loading problems more quickly. All wells with liquid saturations above irreducible levels will develop liquid [un]loading conditions.

The cost of the technologies varies and what will constitute a cost-effective technology will vary from well to well. For example with plunger lifts, the capital, installation, and startup cost is an exponential costing issue based on ever increasing depth of the well (e.g., the cost of a 11,000 to 12,000 foot well might approximate $25,000 to $30,000 for certain operations in East Texas whereas a 1000 foot well may only be $2000 or $3000). Also related to plunger lifts, a "smart technology" cost is dependent on many variables such as well density and availability of a communication network. The communication network for 400 densely spaced wells can easily cost approximately $4 million dollars (average of $10,000/well before adding the cost of the smart controls themselves). The EPA's high range of $18,000/well is not necessarily "high" for many situations. As to artificial lifts, the costs are substantially more. One member indicated capital and installation costs for 11,000 -12,000 foot wells are in the range of $150,000 per well -- much higher than EPA's estimates. Again, the depth of the well influences the costs figures and it is difficult and inappropriate to generalize. The best solution to the liquids unloading problem is a case-by-case decision based on the engineering judgment of the operators.

. . .

As noted above, the feasibility of the use of artificial lift systems is generally site-specific and therefore it is difficult to generalize. Artificial lift systems are just one of the available "tools" or technologies to extend the useful life of a well and are utilized where cost-effective. That said, they tend to be cost-prohibitive on deeper low production gas wells and work best on shallow wells

> capable of setting a pump/plunger/gas lift below the bottom perforations. Some characteristics that discourage the use of artificial lift include deep formations, corrosive production fluids, wells with high scaling tendency, and deviated wellbores. The feasibility of artificial lifts must be assessed according to the conditions of the individual well. One size does not fit all.
>
> In certain situations, gas wells with liquid content that are unloaded are capable of being controlled with flares attached to the tank vents at the production battery. In others, the high pressures in certain regions make routing blowdowns to tanks and flares extremely unsafe. Even wells that are blown down can sometimes be vented through tanks that are controlled in many cases by flares. The capability to do this, however, depends greatly on the conditions of the well bore and the equipment used to control (tanks, flares, etc.) These flares and the associated tanks/tank vents are not specifically designed to accommodate liquids unloading. Regarding the use of flares specifically for liquids unloading events, there are several design and operational issues: (1) liquids unloading are slug flow events that are inconsistent in both gas volumes and quality, (2) consequently, designing a flare for the wide range of operating conditions is challenging, (3) additional equipment may be required to prevent liquids from reaching the flare (separators, etc.), and (4) the intermittent nature of these events is another challenging design condition especially in avoiding smoking conditions, etc. To the extent that EPA contemplates a continuous flare to minimize emissions from these intermittent events, the negative externalities associated with the carbon dioxide emissions from the pilot should be factored into any analysis. To accommodate the operational issues associated with flares and associated equipment designed to specifically address liquids unloading, they would need to be relatively large which could present safety hazards and create local permitting issues.[53]

EPA's proposed Subpart OOOOa seems to leave the door open for potential regulation of emissions associated with liquids unloading and requested comment on the issue. IPAA/AXPC supports EPA's decision to not propose federal standards. The issues outlined above have not been adequately addressed by EPA and remain largely unaddressed.

G. Miscellaneous Requests for Input

- EPA requested input on "pressure-assisted flares." IPAA/AXPC is not entirely clear what EPA is referring to as pressure-assisted flares. To the extent IPAA/AXPC understands the type of flare EPA is referring to, IPAA/AXPC does not believe there is any reason to treat these flares differently than any other flare. Or stated slightly differently, pressure-assisted flares should be treated as any other flare subject to the Subpart OOOO and proposed Subpart OOOOa regulations

[53] *Id.*

- IPAA/AXPC supports a clarification that the storage vessel provisions do not apply to large (e.g., 25,000 bbls or more) tanks used for water recycling, as they have very low emissions but might trigger the 6-ton threshold because of size and volume of throughput. EPA's recognition that this water has very low emissions calls into question whether the smaller "storage vessels" that hold the same type of water, just smaller quantities, should be an affected facility.
- IPAA/AXPC does not support EPA's concepts of independent third-party verification, fugitive emissions verification, and "electronic reporting and transparency" as described as part of EPA's Next Generation Compliance and Rule Effectiveness. As an initial matter, companies should be allowed to verify issues internally. EPA's concept of utilizing certified reviewers would pose a significant problem for the industry in terms of not having enough qualified individuals to conduct the review. Eventually the market would adjust, but in the short term there would be a shortage. EPA's concept would create a problem in an attempt to solve an "issue" that currently does not exist. Finally, industry does not support a continuous parametric monitoring system since this would result in significant costs to companies that do not have supervisory control and data acquisition (SCADA) capabilities and would another add link in the system that could fail. A simpler and better solution would be to require all thief hatch vents to be set at a pressure above that of the main ventline.

V. Control Technique Guidelines for Ozone Nonattainment Areas

Clearly, the CAA provides direction to EPA and states that requires the use of RACM in Ozone nonattainment areas to manage emissions from existing sources. However, EPA's presentation of the CTG for oil and natural gas production facilities fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. Moreover, as IPAA/AXPC demonstrated earlier in these comments, the differences between the oil and natural gas production industry and other industry segments requires a recognition that there are significant differences across the industry in the size and scope of operations that dramatically impact the economic implications of controls. The CTG proposals largely ignore this reality. Any CTG for oil and natural gas production facilities needs to provide an application threshold that excludes marginal oil and natural gas wells. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Without the appropriate recognition of the broad diversity of the oil and natural gas production industry and the need for the CTG to be based on appropriate existing source technologies, serious adverse impacts on American production could result. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

Consequently, IPAA/AXPC requests withdrawal of the current CTG proposal until EPA can address its serious shortcomings and determine whether a broad CTG proposal is appropriate as a RACM approach for oil and natural gas production facilities.

Following is a detailed discussion of the basis for IPAA/AXPC's opposition to the current CTG proposal and reasons why it should be withdrawn.

In its Federal Register notice regarding the *Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry*, EPA provides a pertinent description of the RACM process:

> Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate Ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.
>
> The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.
>
> The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979).[54]

While this description is accurate, EPA wholly fails to meet the test of identifying "control technology that is reasonably available considering technological and economic feasibility."[55]

To understand EPA's failure, it is essential to expand our earlier discussion of the nature of the oil and natural gas production industry. As described earlier, the oil and natural gas production industry differs from other industries because of the inherent reality that its production is not constant. Instead, because of geological realities, production from most oil and

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[54] Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, 80 Fed. Reg. 56,577, 56,578 (Sept. 18, 2015).

[55] *Id.*

natural gas wells peaks at or near its earliest stages of full production. In essence, once the reservoir is opened, the contained pressure in the reservoir forces oil and natural gas through the well bore to the surface. But, this pressure also begins to diminish and with it the flow rate of the well. While various techniques are available depending on the type of formation to improve production, these actions adjust the rate of decline; they do not return the well to its original productivity.

Consequently, over time, wells move from strong producers to marginal ones. In fact, marginal wells are defined in federal law as oil wells producing 15 barrels/day or less and natural gas wells producing 90 mcfd or less. While these are the thresholds, the average marginal wells produce at much lower levels – the average marginal oil well produces 2.7 barrels/day and the average marginal natural gas well produces 22 mcfd. There are business implications to this production depletion as well. As the operating costs of production increase when production decreases, companies sell less productive wells to obtain capital for reinvestment in new production. Many characterize the oil and natural gas production industry as a "food chain" industry with larger companies selling properties that do not fit their production structure to smaller companies. As a result, marginal well ownership is dominated by smaller organizations, many of which are privately held small businesses. As IPAA/AXPC previously stated, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells.

Correspondingly, as production from wells decreases, the physics of emissions changes as well. With less pressure in the well bore, there is less pressure driving emissions to the atmosphere from operating equipment. Even more telling, the most recent research efforts such as those by the University of Texas' Center for Energy and Environmental Resources demonstrate that emissions at oil and natural gas production operations are dominated by a small percentage of sources. Moreover, experience is indicating that when these sources are corrected and maintained, emissions reductions are sustained for long time periods.

Set against this pattern of industry structure and experience, EPA has failed to create a record that demonstrates it made a thoughtful analysis of the technologies it is proposing in the CTG as RACT – particularly in the context of considering technological and economic feasibility. Instead, EPA has arbitrarily applied the BSER technologies in Subpart OOOO and proposed to do so in Subpart OOOOa as they relate to new sources in the context of existing sources. In doing so, EPA fails to appropriately adjust the economic analysis from the NSPS materials to reflect the different circumstance of existing operations.

Among the key factors that EPA understates is the need to focus these regulations on VOC emissions. Because these CTG address VOC emissions, their cost effectiveness and technological appropriateness must be evaluated with regard to their impact on VOC emissions. For example, EPA bases much of its cost-effectiveness determinations on average VOC emissions, but RACT needs to be considered by each state for each nonattainment area. Different oil and natural gas formations produce different vapor compositions including significantly different fractions of VOCs in the vapor. Correspondingly, for the same cost, cost effectiveness will change; it will become less cost-effective as the VOC concentration diminishes.

Similarly, EPA bases much of its analysis on "model" facilities, but facilities differ depending on the nature of their operations. While EPA's draft CTG proposal recommends that facilities with only a wellhead should not be included in its fugitive emissions CTG, it should similarly recognize that facilities with fewer components than the EPA model facility need to be evaluated based on their actual structure rather than presumed to be cost-effectively controlled under the CTG.

These issues become more compelling when the CTG affect marginal oil and natural gas wells. EPA partly recognizes this reality by stating in the context of its fugitive emissions proposed CTG:

> For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved.[56]

This recognition is entirely appropriate and accurate. However, it needs to apply to all of the CTG. Marginal wells are the most vulnerable U.S. production operations – particularly at the current oil and natural gas commodity prices that are well below the prices used by EPA in its cost-effectiveness analyses. Yet, these wells continue to provide a significant portion of American production. Additionally, the CTG should provide that status as a marginal well qualifies for an off ramp from continuing application of the regulations. That is, when a well's production drops to the point where it is considered a marginal well, the facility would no longer be subject to the regulation.

EPA also needs to recognize that its CTG proposal coincides with its decision to lower the Ozone NAAQS. American oil and natural gas operations are located where the resources exist. Unlike manufacturing facilities, they cannot choose where to operate. Historically, much of America's oil and natural gas has been located in largely rural areas. Recent development of American shale resources has placed operations closer to populated areas – many of which are in Ozone nonattainment areas. However, EPA's decision to lower the Ozone NAAQS captures areas that have previously been in attainment. Since a number of these new projected nonattainment areas encompass production areas, these CTG will have a broader and more significant potential impact on U.S. production. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

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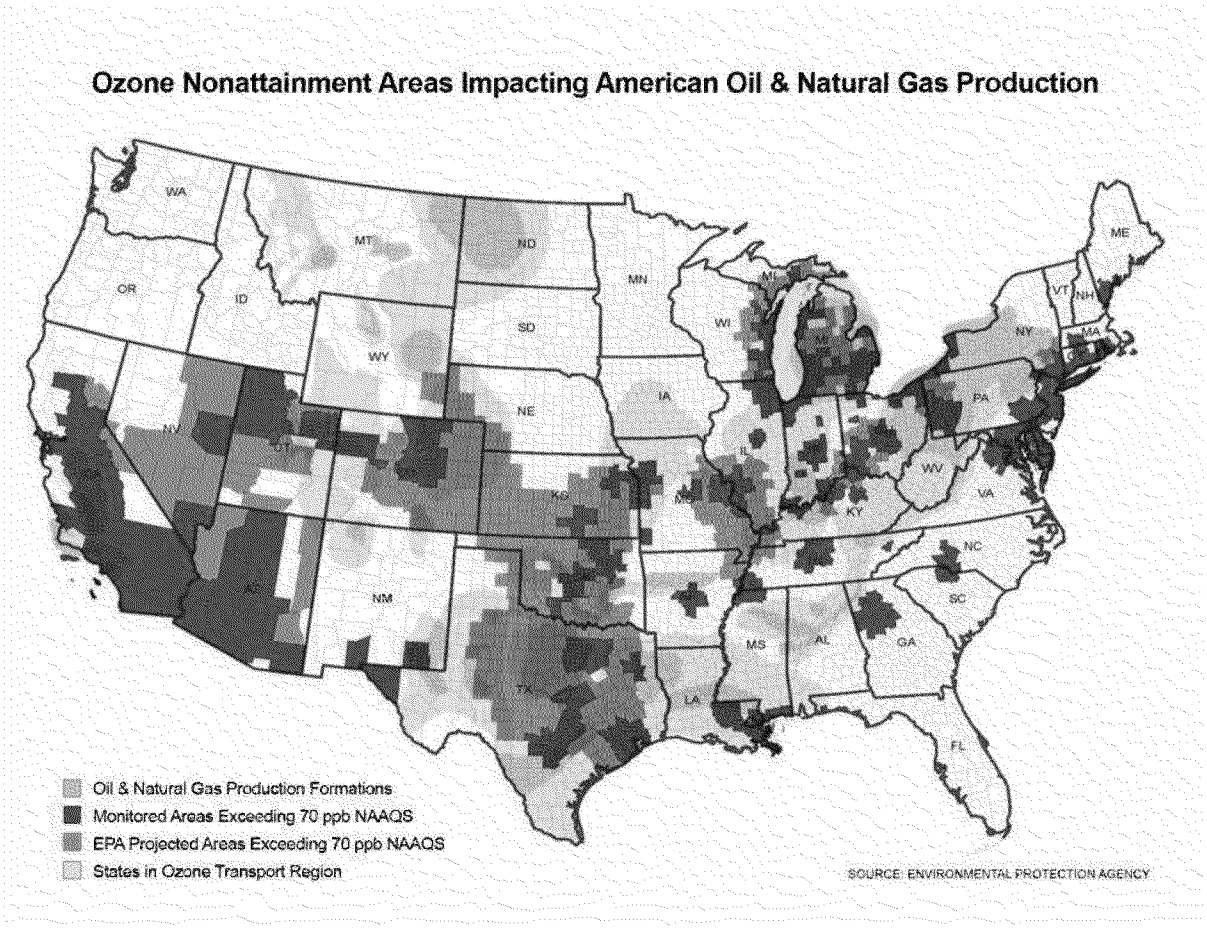
[56] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.



While oil and natural gas production facilities have always been subject to RACM in current Ozone nonattainment areas, the CTG proposal changes the regulatory framework significantly. Part D of the CAA provides for states to impose RACM on existing stationary sources as a part of the requirements to demonstrate attainment or Reasonable Further Progress toward attainment. These RACM requirements, however, apply to stationary sources of a specific size depending on whether an Ozone nonattainment area is classified as Moderate, Serious, Severe or Extreme. Therefore, regulation of existing oil and natural gas production facilities depended both on their size and the status of the Ozone nonattainment area. The CTG proposal in general does not set emissions thresholds for its application. As such, for large or small producers, or large or small emitters, the regulatory burden will apply and will apply far more broadly.

As EPA states with regard to the proposed Subpart OOOOa, "we [EPA] believe that the industry can bear . . . and survive."[57] However, no broad analysis of the collective impact of the CTG proposal on American oil and natural gas production in the context of the revised Ozone NAAQS has been done. Such an analysis should be done for several pertinent reasons.

[57] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

1. Ozone has consistently been the most difficult primary NAAQS for certain areas to meet. The following figures demonstrate the reality of Ozone NAAQS nonattainment. Figure 1 presents EPA's assessment of the areas of the country that fail to meet the 1997 Ozone NAAQS of 84 ppb (8 hour). Figure 2 presents EPA's assessment of the areas of the country that will fail to meet the current Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of its revised Ozone NAAQS by 2025.

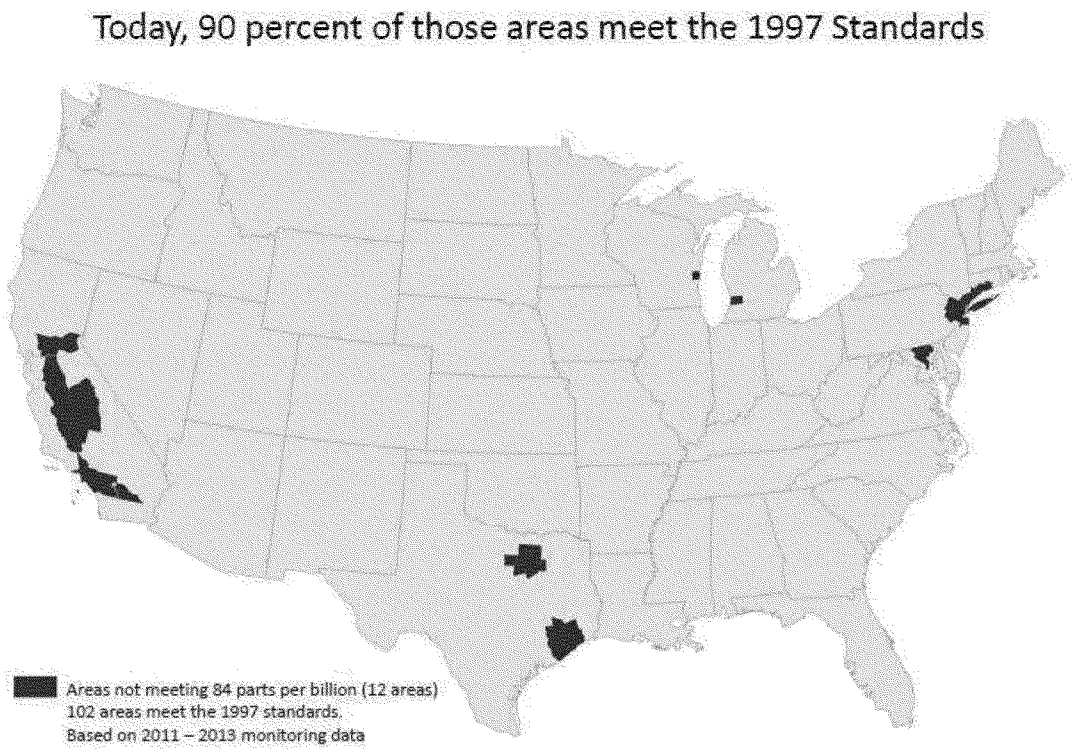


Figure 1

Source: Environmental Protection Agency

Figure 2

Source: Environmental Protection Agency

Figure 3

Source: Environmental Protection Agency

EPA's analysis shows that there are certain areas of the country that are enduring Ozone NAAQS nonattainment areas – areas that cannot meet any Ozone NAAQS that has been promulgated. The same areas that failed to meet the 1997 Ozone NAAQS and the 2008 Ozone NAAQS also will fail to meet the proposed NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the proposed NAAQS will not occur in these enduring nonattainment areas.

Equally important, the regulatory requirements in these enduring nonattainment areas will be no different under the proposed NAAQS than they are under the current NAAQS. These areas are subject to regulation under Part D – Plan Requirements for Nonattainment Areas of the CAA.

Part D was created in the 1990 CAA amendments. It creates a series of specific minimum requirements for each area in Ozone NAAQS nonattainment initially based on the area's ozone monitoring values relative to the Ozone NAAQS. Areas are classified as Marginal, Moderate, Serious, Severe and Extreme. Each classification is given a specific time frame in which to attain the Ozone NAAQS. Importantly, if an area fails to meet the NAAQS in its allotted compliance period, it is reclassified to a

higher classification, required to implement the mandatory requirements and given an extension of time to meet the NAAQS. Part D requirements were initiated after the 1990 CAA amendments with attainment dates ranging from 1993 to 2010. Even with attainment date extensions, these dates have passed.

The significant impact of Part D is that perpetual nonattainment eventually produces a baseline of regulations and requirements of additional annual percentage reductions. Since these areas have been subject to Part D for 25 years, their future regulatory requirements will be the same iterative percentage reductions under the current NAAQS as the new one. Adopting the revised NAAQS will produce the same regulatory requirements for these areas as the current NAAQS.

2. EPA has stated in its support documents for its revised Ozone NAAQS that:

> Existing and proposed federal rules . . . will help states meet the proposed standards by making significant strides toward reducing ozone-forming pollution. EPA projections show the vast majority of U.S. counties with monitors would meet the proposed standards by 2025 just with the rules and programs now in place or under way.

Consequently, these national, federal requirements will essentially protect the overwhelming number of areas that would be placed in Ozone NAAQS nonattainment by the lower NAAQS without any of the local actions that would be required from such categorization.

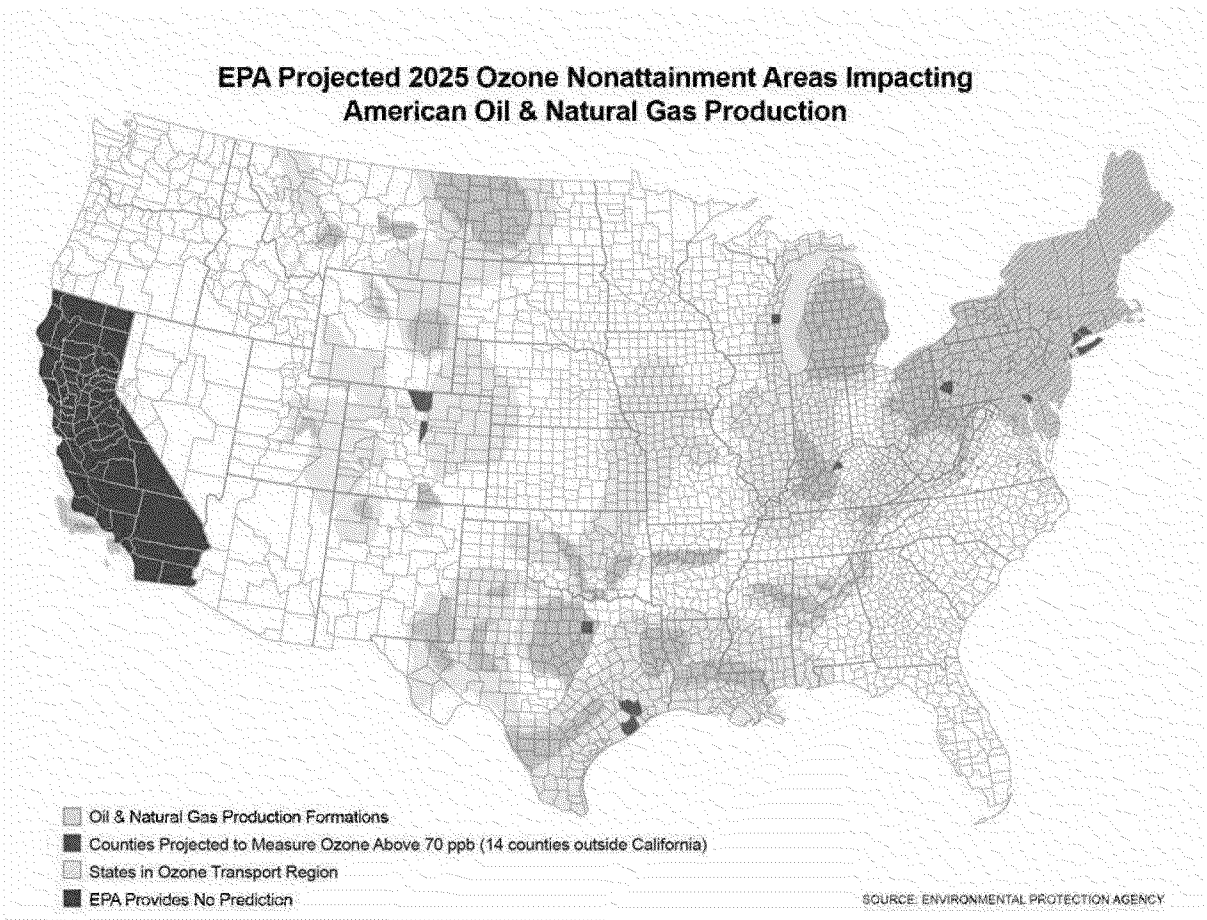
For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the lower NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the revised NAAQS will impose emission controls on new sources in those areas, including offsets, which will be burdensome, cost ineffective and unnecessary since EPA believes these areas would reach attainment using only its national regulations.

Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be "offset" by reductions in existing emissions that are not otherwise regulated. Many of the areas that would fall into initial Ozone NAAQS nonattainment but would later attain the NAAQS are largely rural or with smaller municipalities. These areas will likely have limited existing emissions sources to regulate. These areas will face either an effective construction prohibition or the choice of shutting down existing operations that employ current workers.

3. The proposed oil and natural gas production CTG get pulled into this murky process. Enduring Ozone nonattainment areas already are a possible target for RACM requirements, but those requirements are predicated on the size of the source and

therefore not imposed without consideration of their impact on emissions and with localized consideration of cost effectiveness. For the newly captured Ozone nonattainment areas that EPA believes will meet the revised Ozone NAAQS using national, federal regulations – an assessment made without the inclusion of the proposed CTG – the application of the proposed CTG is unnecessary to reach attainment. However, because the CTG would be applied and would be applied to such small sources, these reductions are also removed from the possible pool of emissions that could be managed as a part of emissions offsets needed to build new facilities. In many of these areas, new facilities are likely new oil and natural gas wells. Consequently, the impact of the CTG would be to limit new production.

For these reasons, EPA must fully assess the energy, economic and environmental consequences of implementing the proposed CTG in the context of the revised Ozone NAAQS. IPAA/AXPC believes that EPA cannot justify the current CTG at this time. As the following graphic shows, EPA projects that only a few areas will remain in Ozone nonattainment in 2025.



This projection is based on regulatory actions taken without the proposed CTG. It demonstrates that the CTG is not essential to Ozone NAAQS attainment. Certainly, in some enduring

nonattainment areas some oil and natural gas production facilities would be subject to RACM, but these decisions would be based on local conditions and the economic circumstances of the oil and natural gas production operations in those areas. Finalizing the proposed CTG would make all oil and natural gas production operations subject to the CTG without a compelling need – based on EPA's own projections of Ozone attainment – and without the opportunity to assess local need. Moreover, it would eliminate possible actions that could facilitate new construction as offsets and thereby unnecessarily threaten economic growth in these areas. If EPA finalizes an oil and natural gas production CTG without assessing all of these consequences, it can only be viewed as arbitrarily ignoring significant implications that EPA has the responsibility to address.

It is pertinent to address the methane emissions issue here, too. While this proposed oil and natural gas production CTG is written to manage VOC emissions, it has been proposed as a part of the Administration's Climate Action Plan and is partly a surrogate for methane emissions management. However, as IPAA/AXPC stated earlier in these comments, the requirements already in regulation under Subpart OOOO more than achieve the Administration's methane reduction targets for the oil and natural gas production segment of the Climate Action Plan. This CTG needs to be addressed on its merits and its consequences weighed with regard to Ozone NAAQS nonattainment.

In addition to these general concerns, IPAA/AXPC has issues associated with the specific CTG proposals.

A. Fugitive Emissions

IPAA/AXPC identified a series of specific issues in the discussion of the Subpart OOOOa proposal that apply in the CTG context as well. Here, this discussion will focus on some of those issues and raise others that arise because of its application to existing sources.

First, EPA's approach to a fugitive emissions program fails to recognize the nature of these emissions at oil and natural gas production facilities. This emissions arena is characterized by "fat tail" emissions where a few components within the facility account for the overwhelming amount of the releases. At the same time, it is an arena where the appropriate regulatory formulation is still being identified. Several states have initiated fugitive emissions programs, and each differs from the others. Clearly, it will take some time to determine the efficacy of approaches in order to assure that a cost-effective program is defined. Into the middle of this uncertainty, EPA proposes the most burdensome approach with expectations of success that are not founded on experience. Rather than bullying its way into the arena, EPA has two far better approaches it could take. One is to watch the emerging state programs and use their results to design a program. The second is to work with industry to develop voluntary initiatives that would reflect the emerging understanding of fugitive emissions patterns. IPAA/AXPC believes that EPA should withdraw its fugitive emissions proposals until more is known about the best approaches to managing them.

Second, initial experiences with state programs are revealing that once a "fat tail" source is corrected through appropriate maintenance, its emissions do not increase – at least for long periods of time. In fact, because the current state programs have been operating for a limited

amount of time, some sources that have been fixed have not needed a second action. However, like its NSPS proposal, EPA creates a framework of shifting monitoring frequencies that are not justified based on experience. If EPA continues to pursue its proposal, it should rely on an annual inspection cycle to create a stable planning framework.

Third, when states have or create their own fugitive emissions programs, these programs should be considered as meeting CTG requirements.

Fourth, IPAA/AXPC supports excluding smaller facilities (e.g., marginal wells producing 15 barrels/day of oil equivalent or less) from the scope of the fugitive emissions program and believes that facilities that are initially included in any program should be excluded when their production falls below the threshold. IPAA/AXPC agrees that a fugitive emissions program should not apply to facilities with only a single wellhead. Further, EPA bases its program on a "model" facility with an expected number of components. IPAA/AXPC recommends that sites with less than the model facility components should be excluded from the fugitive emissions program.

Fifth, IPAA/AXPC believes that EPA is understating the costs of its fugitive emissions program and overstating its benefits. As IPAA/AXPC stated in discussing the NSPS proposal, EPA relies on technologies that are costly while not demonstrating those technologies are necessary to achieve benefits. For example, EPA is enamored with the use of specific OGI technologies. EPA places far too much faith that OGI can detect emissions accurately. Moreover, by using this technology, it drives compliance costs excessively. As described earlier, compelling the expenditure of more than $100,000 per FLIR camera is a burden not easily borne by existing operations where production rates are lower than new facilities in today's economic climate. EPA's proposal immediately demands confidence that the expenditure will result in substantial savings. However, nothing in EPA's CTG proposal demonstrates that it has realistically evaluated the effectiveness of this program at existing facilities. Past CTG have provided a threshold cost effectiveness test that is absent here. Rather, EPA calculates costs/ton of reduced emissions for various technologies whether they are appropriate as RACT. For example, EPA rather cavalierly discounts the costs/ton for oil wells – which exceeds $10,000/ton in all of its cases and reaches more than $25,000/ton in some – by stating "[t]he cost of control for natural gas well sites and gathering and boosting stations is considered to be reasonable."[58] Implicitly, the cost of control for oil well sites is not reasonable, but EPA proposes the same RACT requirements. IPAA/AXPC believes that oil well sites should be excluded from the CTG and that any natural gas well site program needs to be reconstructed to focus on high-emitting sources with flexibility to use more cost-effective approaches.

EPA errs in locking in current technologies, like OGI, that may well be far less cost-effective than new approaches that may arise as state programs learn from experience. As with the NSPS proposal, EPA needs to allow the development of knowledge in managing these fugitive emissions before framing a rigid and ineffective mandate.

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[58] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

B. Storage Vessels

There is a vast difference between regulating new storage vessels and existing ones. Specifically, a new vessel can be designed to accommodate a vapor collection system whether it is for recovery or combustion. Once built, both the vessel and the system can be maintained to assure that they are operating effectively and safely. Because a CTG addresses existing facilities, there is no certainty that the storage vessels will be capable of accepting the equipment needed to capture vapors. Vessels deteriorate over time despite maintenance, and if the structural integrity is compromised by the additional equipment, a safety issue arises.

In this context, and more generally, EPA's cost estimates must be scrutinized. EPA suggests that vapor recovery units (VRU) or combustors can be considered RACT for vessels with emissions of 6 tons/year or more. However, if a storage vessel cannot safely operate with additional equipment, the entire vessel would have to be replaced, if replacement is even economically feasible. EPA does not consider this situation in calculating its cost effectiveness, but it should because the consequences would considerably change the determination of RACT. For example, at some facilities under current economic conditions, the cost of a new storage vessel would not be economically feasible based on the facility's production rates.

Additionally, IPAA/AXPC believes that marginal well facilities should be excluded from the scope of the CTG. Clearly, the burden of adding capture equipment – and certainly the burden of replacing storage vessels – cannot be readily borne by marginal well operations. EPA relates emissions to production rates as shown in the following table. The information contained in the table shows that marginal well operations fall well below even EPA's presumed RACT threshold of 6 tons/year. Consequently, rather than deliberate on emissions estimates, the straightforward approach to defining the scope of the storage vessel CTG would be to exclude marginal well operations. Similarly, when a facility's production levels fall to the point when it becomes a marginal well operation, it should no longer be required to operate any vapor capture system. Beyond that, there should be the opportunity – like there is in Subpart OOOO – to demonstrate that uncontrolled emissions levels are below 4 tons/year to obtain an exclusion from the storage vessel CTG.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[13]

Production Rate Bracket (BOE/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html.
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

C. Pneumatics

The proposed CTG addresses both pneumatic controllers (regulated for new sources under Subpart OOOO) and pneumatic pumps (proposed for new source regulation under Subpart OOOOa). IPAA/AXPC believes that these requirements should not apply to marginal well facilities. In addition, EPA needs to clarify that the CTG does not apply to pneumatics with continuous emissions less than 6 scf/h.

D. Compressors

The proposed CTG addresses a subset of compressors as follows:

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.[59]

However, it makes no distinction based on the size of the facility. IPAA/AXPC believes that the CTG should not apply to marginal well facilities and that its application should be terminated when a facility becomes a marginal well operation.

E. Conclusion

The proposed oil and natural gas production CTG should be withdrawn. It fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. It largely ignores the differences between the oil and natural gas production industry and other industry segments that require recognition of the significant differences across the industry in the size and scope of operations. These differences dramatically impact the economic implications of controls. While a portion of the CTG proposal creates an application threshold that excludes marginal oil and natural gas wells, a similar provision should apply to all of its provisions but does not. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

VI. Comments on Source Determination Proposal

The EPA is soliciting comments on a potential revision of the process for determining the nature of a source for certain emissions units in the oil and natural gas sector. Among these are facilities that produce oil and natural gas. The proposal addresses CAA new source permitting

[59] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

under the Prevention of Significant Deterioration (PSD) program, the Nonattainment New Source Review (NNSR) program, and Title V permitting program. IPAA/AXPC believes that establishing certainty regarding source determinations provides an important benefit to the permitting process. Below are a series of recommendations and comments that address IPAA/AXPC's concerns regarding the EPA proposal. However, at the outset, IPAA/AXPC would observe that, while there have been some specific issues associated with past interpretations of oil and natural gas production sources, the issue of source determination applies to all stationary sources.

Similarly, this issue of changing the structure of source determination must conform to the constraints of past interpretations. As EPA characterizes its actions on source determination in the Federal Register:

> Adhering to the statutory language in CAA section 111(a)(3), we have defined the term ''stationary source'' to mean ''any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant'' [40 CFR 52.21(b)(5); 40 CFR 51.165(a)(1)(i); 40 CFR 51.166(b)(5)]. We have then further defined the four statutory terms ''building, structure, facility, or installation'' collectively in our NSR regulations to mean ''all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control),'' where the ''same industrial grouping'' refers to the two-digit Standard Industrial Classification code [40 CFR 52.21(b)(6); 40 CFR 51.165(a)(1)(ii); 40 CFR 51.166(b)(6)]. These three regulatory factors: (1) Same industrial grouping; (2) location on contiguous or adjacent properties; and (3) under the control of the same person or persons must be evaluated on a case-by-case basis for each permitting decision.[60]

EPA needs to confirm clearly that its actions on source determination operate within this larger framework.

EPA presents two approaches to source determination. These comments focus principally on Option A – defining the source based on proximity – because IPAA/AXPC strongly opposes Option B, which includes exclusively functionally interrelated equipment.

Much of the history of the source determination question for oil and natural gas production occurred prior to the significant shift in development to shale formations and the evolution of technology that has been so successfully applied to produce those resources. These changes in the nature of oil and natural gas development alter the physical aspects of producing operations. Oil and natural gas production operations have moved from a framework where numerous vertical wells were drilled in developing a resource play to a framework where development relies on significant horizontal legs providing access to the resources. Correspondingly, a typical well site will now include numerous individual wells ranging from six

[60] Source Determination for Certain Emission Units in the Oil and Natural Gas Section, 80 Fed. Reg. 56,579, 56,580 (Sept. 18, 2015) (to be codified at 40 C.F.R. pts. 49, 51, 52, *et al.*).

to twelve to, sometimes, twenty. As a result, the concepts that drove past EPA actions to consider source determination approaches that aggregate multiple well sites together – essentially the "daisy chaining" concept the EPA seeks to avoid in this proposal – no longer reflect the industry's common practices.

Similarly important, the regulatory structure that affects oil and natural gas production has changed significantly. Since the beginning of 2015, the industry has been subjected to NSPS requirements on completions of new hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Currently pending are proposals to regulate new hydraulically fractured oil wells, pneumatic pumps, compressors, and fugitive emissions. These regulations apply to virtually every new well site and manage the emissions. Consequently, the issue of emissions management is essentially settled, and the principle issue of the source determination rule will be the regulatory burden for the specific permitting programs of the proposals – PSD, NNSR, and Title V. Because emissions are not the driving factor in the decision, EPA should move toward limiting burdens rather than expanding them.

These factors shape our view that Option A – *Define Source Based on Proximity (Similar to the NESHAP)* – is the far better framework to address source determination. As EPA characterizes Option A:

> Under the first, and currently preferred, option for which the EPA is taking comment, the EPA proposes to define "adjacent" such that the source is similar to that in the NESHAP for this industry, Subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (40 CFR 63.760). Under this option, the "source" for oil and natural gas sector activities is presumed to be limited to the emitting activities at the surface site, and other emitting activities will be considered "adjacent" if they are proximate. Thus, under this first option, two or more surface sites must be considered as a single source if they share the same SIC code, are under common control, and are contiguous or are located within a short distance of one another.
>
> We prefer this option because we believe that a definition that centers on a surface site is familiar to the industry and the regulators because of the current NESHAP requirements, so it will streamline permitting. We also believe that a definition focused on a surface site most closely represents the common sense notion of a plant for this industry category. Surface sites that are not in close proximity to one another may be on a separate lease which may not align with the common sense notion of a single plant. In addition, we believe that this definition is consistent with Congress' intent, at least as they expressed it with regard to [hazardous air pollutants (]HAPs[)], as discussed previously.[61]

IPAA/AXPC essentially agrees with EPA's characterization and its rationale. Where IPAA/AXPC differs relates to an issue where EPA seeks specific comments – whether it is

[61] *Id.* at 56,586-7.

appropriate to establish a specific distance within which to consider multiple surface sites as a single source, and if so, what that distance should be. EPA is proposing a distance of a ¼ mile. IPAA/AXPC believes that EPA should, instead, adhere to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.

This approach improves on the proximity concept because it avoids picking an arbitrary distance, such as a ¼ mile. Moreover, it readily addresses another issue that EPA raises – "daisy-chaining". EPA is correct to be concerned that linking one site to another through its proximity invites the opportunity to link a third or a fourth or more sites solely on the basis of proximity. There is no value in daisy-chaining since the individual sites are each subject to the emissions management requirements under the appropriate NSPS or whatever additional regulations apply.

If, however, EPA persists in utilizing a specific distance, it is correct that some states use ¼ of a mile as a bright line to exclude needless source determinations for facilities outside that distance. However, most states then conduct a case-by-case source determination for facilities inside the ¼ mile based on proximity and the "common sense notion of a plant." Therefore, if EPA persists in utilizing a specific distance, it should follow the example of most of the oil and gas producing states and use the bright line to trigger a case-by-case source determination inside that bright line. It is also important to recognize that using an arbitrary distance raises questions of daisy-chaining, and EPA should have language either in the rule or the preamble to state that facilities should not be daisy-chained. EPA has also asked from where a specific distance should be measured. We suggest that the distance be based on the center of the new source triggering the source determination to the center of any nearby facility.

EPA should reject Option B – *Define Source To Include Exclusively Functionally Interrelated Equipment.* Option B essentially invites daisy-chaining. It creates the opportunity to link multiple facilities regardless of the distances between them. For example, as EPA states "[e]xclusive functional interrelatedness might be shown by connection via a pipeline or other means, because of the physical connection between the equipment."[62]

This characterization largely parrots the circumstances in the *Summit Petroleum Corp. v. U. S. Environmental Protection Agency*, 690 F.3d 733 (6th Cir. 2012) case. In this case, as EPA describes in its discussion of these proposals:

> In the decision, the Court said that the EPA's use of interrelatedness in determining whether sources were "adjacent" is unreasonable and contrary to the plain meaning of the term as currently used in EPA's regulations. The two judges in the majority found that the term "adjacent" was unambiguous and its plain meaning related only to physical proximity, and thus could not include

[62] *Id.* at 56,587.

> consideration of functional interrelatedness. The EPA sought rehearing of the Court's decision, but that request was denied.[63]

Why EPA would suggest moving back toward this judicially rejected approach is unfathomable. More importantly, it does not create any environmental benefits, because, as stated above, the existence of the current and proposed EPA oil and natural gas production regulatory requirements would apply to the separate facilities. Option B would only create substantially expanded regulatory burdens.

In conclusion, IPAA/AXPC believes that EPA's appropriate choice is a modified Option A relying on the use of a contiguous border to aggregate sources if aggregation is appropriate. To facilitate clarity on this issue, IPAA/AXPC suggests adding the following definition where appropriate in the Code of Federal Regulations:

> "Contiguous or adjacent properties" mean surface areas with an affixed building, structure, facility or installation including permanently graded or cleared areas for such building, structure, facility or installation, that share an edge/boundary, physically touch, and are adjoining or physically abutting.

CONCLUSION

IPAA/AXPC values the opportunity to comment on the above referenced regulatory proposals. The oil and natural gas production industry has worked closely with EPA over the past decade to promulgate reasonable, cost-effective regulations on air emissions. While industry objected to various aspects of the Subpart OOOO regulations controlling VOC emissions from various sources within the oil and natural gas sector, through the administrative reconsideration process and revisions to Subpart OOOO, many of the issues have been addressed without protracted and costly litigation. The proposed Subpart OOOOa and CTG regulations seem to represent a departure from a willingness on the part of this Administration to promulgate reasonable, cost-effective, and most importantly, needed regulations.

EPA's pollutant of concern is methane. Unlike other "pollutants" and other industrial "products," methane is not treated as a pollutant in the oil and natural gas industry – it is a valuable product. Unlike other industries, market forces are constantly at work to minimize what EPA views as a pollutant and our industry views as a product. The fact methane is a primary constituent of what this industry produces explains, in large part, why emissions from the exploration and production segment of the oil and natural gas sector have gone down while production has gone up (see Section I above). In reality, most of the reductions are a function of voluntary measures by producers to retain/capture methane or state regulatory programs where oil and natural gas production has increased dramatically in the past decade.

A central theme to IPAA/AXPC's comments is that the proposed Subpart OOOOa regulations are unnecessary and the CTG proposed regulations are, at best, premature. The

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[63] *Id.* at 56,584.

EPA's legal foundation and basis for the proposed Subpart OOOOa and CTG regulations are dubious and invite legal challenge. It is arbitrary and capricious for EPA to base its proposed methane regulations (NSPS and CTG) on a model that predicts the social cost of methane. The irony is that EPA can accomplish a majority of its goals with modifications to existing regulations and attainment of the current Ozone NAAQS. The cost of EPA's proposed NSPS and CTG is not justified.

A. Proposed Methane New Source Performance Standards Summary Comments

- Regulations cannot be based on what EPA "believe[s]" "the industry can bear . . . and survive."[64]
- EPA's "consistency," patchwork "endangerment finding," and global warming concerns do not warrant direct regulation of methane emissions from the oil and natural gas sector.
- EPA's failure to evaluate the cost associated with the potential regulation of existing sources under Section 111(d) is arbitrary and capricious.
- States (and operations within those states) should not be penalized for taking early action to address emissions from the oil and natural gas sector, i.e., compliance with essentially equivalent state programs should be deemed compliance with the finalized Subpart OOOOa regulations.
- EPA's focus on fugitive emissions at well sites and compressor stations is premature and not supported by reliable cost/benefit data.
  - EPA's request for input and comment on numerous aspects of the proposed regulations is indicative of an issue that regulators and industry are still learning to address.
  - The "corporate fugitive management program" is a logical way to address the issue, but regulators and companies need time to determine what such a program should look like.
  - EPA's cost-effectiveness analysis for the proposed regulatory package suffers from shortcomings on both sides of the equation: for the reasons set forth above, the costs are understated and the benefits are overstated or unsupported.
  - States with the most active shale plays are learning valuable information on how to reduce fugitive emissions. EPA should not rush to judgement and establish federal standards that will be inconsistent, duplicative and potentially unnecessary because of state efforts.
  - For the reasons stated above, EPA should not dictate a specific technology for determining "leaks." OGI may be appropriate in certain instances, but EPA's selection of one technology is arbitrary and capricious.
  - EPA's proposed approach to determining the frequency of LDAR surveys based on percentage of leaking components demonstrates its lack of understanding of the issues associated with fugitive emissions. As discussed above, EPA's

[64] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

proposed regulations would impose significant costs on the industry with dubious environmental benefit.
  - IPAA/AXPC supports EPA's proposed exclusions but seeks clarification that the 15 boe exclusion also serves as an off ramp to reduce the burden of the proposed regulations.
- Oil well RECs are not the same as RECs at natural gas wells.
  - IPAA/AXPC questions if EPA has documented new information to justify the cost-effectiveness of RECs on oil wells. The economics and engineering limitations at oil wells are different than natural gas wells, and EPA has failed to adequately differentiate between the two and justify RECs at oil wells.
  - IPAA/AXPC supports the limited exclusions to the oil well REC requirements but suggests clarification as to the requirements associated with noncombustible gas.
- EPA's proposed regulation of pneumatic pumps fails to adequately reflect the complexity, cost, and safety issues associated with sending captured natural gas to an existing combustion device. IPAA/AXPC believes that if the costs associated with such complexity were adequately reflected, the proposed regulations would not be cost effective.
- IPAA/AXPC supports EPA's proposed regulations that indicate the compressor rules do not apply to compressors at the wellsite but requests clarification that a similar exclusion applies under the proposed CTG.

B. Proposed CTG Summary Comments

- The CTG regulations must be based on a technological analysis for RACM instead of arbitrarily transposing new source BSER requirements to existing sources.
- The CTG regulations need to recognize differences across the oil and natural gas production industry that recognize size and scope of operations.
  - Marginal oil and natural gas production facilities should be excluded from all of the CTG.
- The CTG regulations must be based on their applicability to manage VOC emissions in Ozone NAAQS nonattainment areas.
  - EPA has failed to provide justification for the CTG as necessary for Ozone NAAQS attainment and, in reality, EPA's projections of Ozone NAAQS attainment in 2025 demonstrates the CTG are not necessary.
  - Implementation of the CTG in the absence of a demonstrated need is counterproductive and unnecessarily constrains economic growth.

C. Proposed Point Source Determination Summary Comments

- EPA should adopt a Source Determination definition that adheres to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.
- EPA should reject the use of functionally related equipment as a consideration in adopting revisions to its Source Determination definition.

If EPA has any questions or concerns, please do not hesitate to contact us.

Sincerely,

Lee Fuller
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ATTACHMENT A

ACRONYM INDEX

AAPL	American Association of Professional Landmen
AEO	Annual Energy Outlook
AESC	Association of Energy Service Companies
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	Fifth Assessment Report
AVO	audio/visual/olfactory
AWEA	American Wind Energy Association
AXPC	American Exploration and Production Council
boe	barrels of oil equivalent
BSER	best system of emission reductions
CAA or Act	Clean Air Act
CMSA	Consolidated Metropolitan Statistical Area
CTG	Control Technique Guidelines
EIA	Energy Information Administration
FLIR	forward looking infrared
GHG	Greenhouse Gas
GOR	gas-to-oil ratio
HAPs	hazardous air pollutants
IADC	International Association of Drilling Contractors
IAGC	International Association of Geophysical Contractors
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
LDAR	leak detection and repair

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NAAQS	National Ambient Air Quality Standards
NCA3	2014 National Climate Assessment, Climate Change Impacts in the United States
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGO	non-governmental organizations
NNSR	Nonattainment New Source Review
NSPS	New Source Performance Standards
NSWA	National Stripper Well Association
NYMEX	New York Mercantile Exchange
OGI	optical gas imaging
OTR	ozone transport regions
PESA	Petroleum Equipment & Services Association
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measures
RACT	reasonably available control technology
RECs	reduced emissions completions
RIA	Regulatory Impact Analysis
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
SC-CH_4	social cost of methane
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
TSD	Technical Support Document
USG	United States Government
USGCRP	U.S. Global Change Research Program
USOGA	U.S. Oil & Gas Association

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VOC	Volatile Organic Compound
VRU	vapor recovery units
WEA	Western Energy Alliance

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April 22, 2015

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

VIA ELECTRONIC MAIL

RE: Comments of the Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association and the Virginia Oil and Gas Association -- Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel; Docket ID No. EPA-HQ-OAR-2010-0505.

Dear Administrator McCarthy:

The Independent Petroleum Association of America ("IPAA"), Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association, and the Virginia Oil and Gas Association (collectively, the "Independent Producers") appreciate the opportunity to submit comments on the proposed rule entitled "Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel" ("Proposed Rule") and published in the Federal Register on March 23, 2015 (80 Fed. Reg. 15180).

As discussed in the comments filed by the Independent Producers on the July 17, 2014 proposed amendments to the original New Source Performance Standards ("NSPS") for the oil and natural gas sector, the above associations came together, in large part, to comment on the original rule (individually, or as a member of IPAA), published on August 16, 2012; petition the United States Environmental Protection Agency ("EPA") for reconsideration on October 15, 2012; and file a legal challenge in the United States Court of Appeals for the District Circuit to the August 16, 2012 final rule because there are aspects of the final rule that disproportionally impact conventional wells and energized wells – particularly as it relates to reduced emission completions ("RECs"). As noted in the March 23, 2015 Federal Register notice, the Independent Producers comments on the July 17, 2014 proposed rule were timely filed on August 18, 2014 but not included in the record and not considered or addressed in the final rule published

December 31, 2014. Pursuant to EPA's instructions in the Proposed Rule, the Independent Producers are not repeating or resubmitting their August 18, 2014 comments but simply requesting that the EPA incorporate them by reference with these comments.

The Proposed Rule asks for comments on primarily two issues: the definition of a "storage vessel" and the definition of a low pressure well. For the reasons set forth in the preamble, the Independent Producers support the revisions to remove the "connected in parallel" and "installed in parallel" language from the definitions of "returned to service" and "storage vessel" in 40 C.F.R. § 60.5430. While the terms "connected in parallel" and "installed in parallel" may have been included in the definitional terms inadvertently, the changes might be read to significantly expand the scope of the NSPS. The Independent Producers appreciate EPA explaining that it was not the intent of EPA to expand the scope of the NSPS and it was moving relatively quickly to rectify the mistake. As discussed in the Gas Processors Association request for administrative reconsideration, storage vessels have historically been placed next to each other and sometimes operated in parallel or in series – with no intent of decreasing emissions from each tank. Obviously, there is an incentive to keep emissions from a storage vessel below the 6-ton per year applicability threshold – and the regulations contemplate ways to do that legally. EPA has explained its concern and taken the steps necessary to forewarn industry that connecting storage vessels in parallel to circumvent the NSPS 6-ton threshold is not allowed under the regulations.

The Independent Producers concern with EPA's definition of a low pressure well – from the beginning in 2012 – is that it does not accurately define what industry has historically defined and recognized as a low pressure well. Additionally, because EPA's definition does not accurately delineate low pressure wells, the NSPS, as proposed, will subject a subset of wells to RECs where the operation of a separator is not physically possible thereby making the wells uneconomical as a result of being subject to REC requirements. The Independent Producers' August 18, 2014 comments reference Exhibit 5 of Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells which discusses the volume of gas required to lift liquids – a parameter associated when RECs are feasible. Building on Exhibit 5 and utilizing the limited variables within EPA's definition (reservoir pressure and sales line pressure), the following Table shows the difference between EPA's definition and industry's proffered definition. Industry would consider all of the combinations of well depth and sales line pressure in the Table as a low pressure well. Whereas EPA's definition would only define the cells in red as "low pressure" wells.

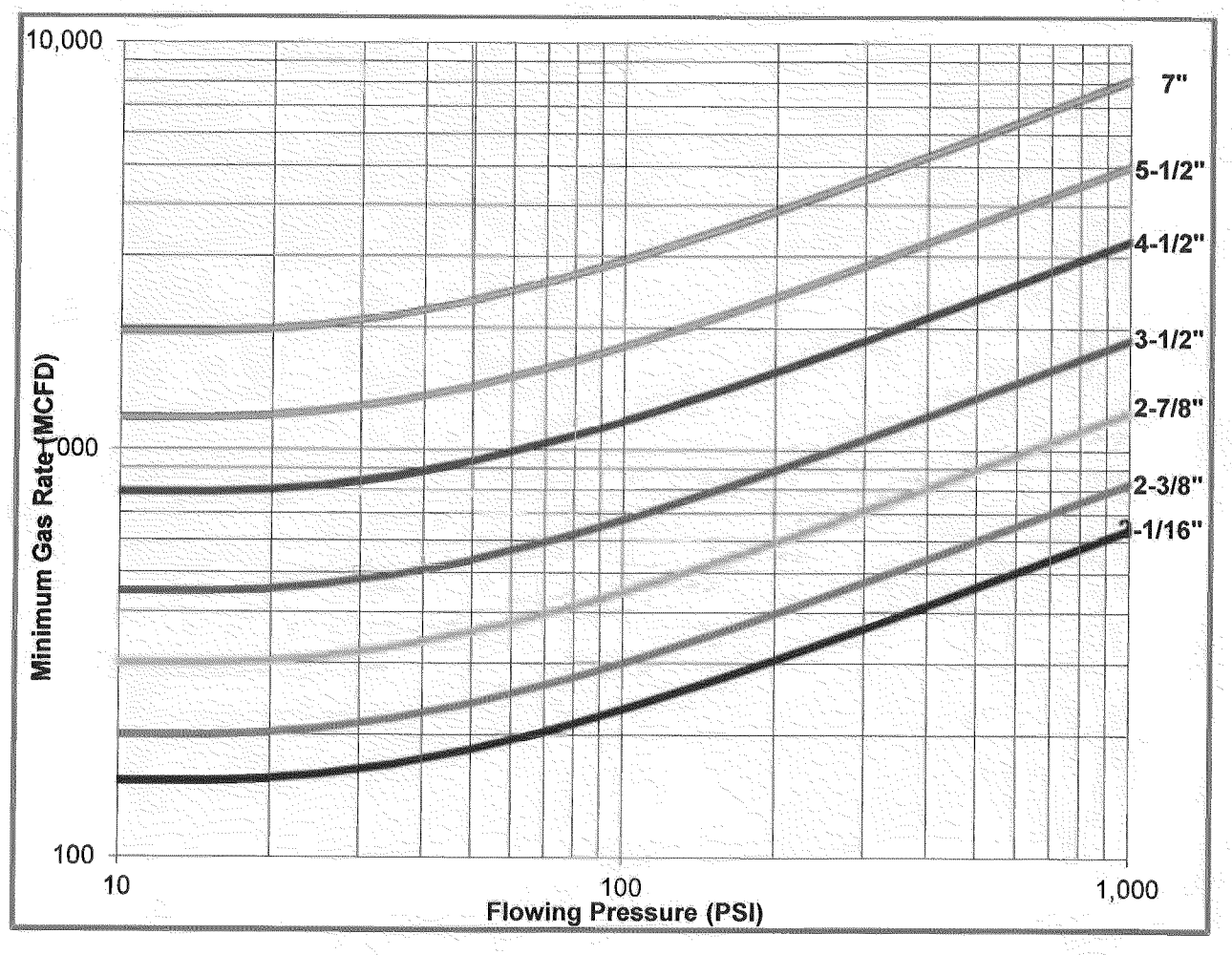
Reservoir Pressure 0.4645 psi/ft

Reservoir Depth \ Flowline Pressure	25	50	100	200	300	400	500	600	700	800	900	1000	1100	1200
1000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

^((0.445 psi/ft * TVD* Resv_Pressure_Grad)-(0.038 psi/ft * TVD)-67.578 psi) -Sales Line Pressure in psi

The data presented in this Table demonstrates the limitations of EPA's definition. Reducing the definition of a low pressure well to a mathematical formula that can be calculated on a "basic hand-held calculator " fails to capture the complex reality of when a particular well is "under pressured" and not able to overcome the pressure associated with a column of water and sales line pressure. The permeability of the reservoir and other reservoir characteristics play a critical role in determining when a well is low pressure well or under-pressured. In addition to overcoming the hydrostatic pressure and sale line pressure, the separator necessary for the REC adds to the pressure which must be overcome for gas to flow from the reservoir. The separator pressure is arguably the controlling parameter on when a REC is feasible versus the sales line pressure. Unlike the sales line pressure, which is easily known, separator pressure can vary greatly depending on gas and liquid rates, liquid composition and equipment limitations. EPA's definition does not take separator pressure into account thereby making the definition overly conservative. Admittedly, the alternative definitions provided by the Independent Producers does not contain an adjustment for separator pressure either, but nonetheless, for the reasons set forth in the August 18, 2014 comments, the definition is more accurate and is inclusive of wells recognized by the industry as "low pressure".

The reality is that a "low pressure" or "under-pressured" well is not easily defined by simply entering well depth and reservoir pressure into a handheld calculator. In addition to the pressure associated with the separator, in order for a separator to function, there must be a sufficient volume of gas (at appropriate pressure) to lift the associated liquids and overcome the pressure of the separator. If that gas rate is not achieved, the well will load up and a REC will not be possible. The gas rate necessary for a REC varies based on reservoir pressure and casing/tubing diameter. The following Coleman curves illustrate this point.



SPE20280 A New Look at Predicting Gas-Well Load-Up, Coleman, Clay, McCurdy, Norris. As the pressure and casing diameter increase, so must the gas rate. Again – without sufficient gas volume, the well will not be able to lift liquids and a REC will not be possible. In reality, most wells produce a significant fraction of liquids during flowback and early production. Wells with low reservoir pressure are particularly susceptible to liquid loading. This is further exasperated by the fact that during stimulation these wells are often being flowed-back up large diameter casing rather than tubing – thus requiring greater gas rate and pressure from the reservoir (see Coleman Curves). Certain wells require artificial lifts to assist in the liquid unloading. If the well requires an artificial lift, the well is clearly a low pressure well.

The Independent Producers have pursued an accurate, workable definition of low pressure for over three years at this point. We have met with and discussed the issue multiple times with EPA. Both sides have searched for a simple, clear formula or bright line. In the field, it's not that easy – there is a "certain art" or technique associated with the science. EPA is concerned that operators will try to circumvent the REC requirements by claiming to be a low pressure well. The reality is that if a REC is feasible, the operator has the economic motivation

to undertake the REC. But there is a category of wells, low pressure wells, where RECs are not only uneconomical, but it is not technically feasible. The Independent Producers generally support the preamble discussion of "technical feasibility" in the December 31, 2014 rule as it pertains to the difference between the initial flowback stage and separation flowback stage. That discussion is also applicable to the ability of low pressure wells to conduct RECs. Reducing subjective calls based on fact specific situations and engineering judgment to a mathematical formula or descriptive narrative is extremely difficult if not impossible. It is akin to the United States Supreme Court Justice Potter Stewart's discussion of obscenity – "I know it when I see it . . . ." The Independent Producers appreciate that a regulatory scheme cannot and should not be that subjective. Neither EPA's definition nor the Independent Producers' definition is perfect. But based on the input of the operators in the field and the technical consultants/engineers familiar with low pressure wells[1], the alternative definitions provided by the Independent Producers are more accurate than EPA's definition.

If the EPA has any questions or concerns regarding the comments, please do not hesitate to contact me.

Sincerely,

James D. Elliott (SDS)

James D. Elliott

cc: Bruce Moore
Amy Branning
Lee Fuller, IPAA Vice President of Government Relations
Charlie Burd, IOGA-WV Executive Director
Andrew V. McNeill, KOGA Executive Director
Lou D'Amico, PIOGA Executive Director
Shawn Bennett, OOGA Executive Vice President
Matt Stone, INOGA President
Brad Richards, IOGA Executive Vice President
Greg Kozera, VOGA President

[1] It should be noted that these comments and previous comments relate only to "low pressure gas well." As EPA contemplates potential controls on low pressure oil wells, the Independent Producers respectfully request the opportunity to discuss what emission controls for oil wells MAY be warranted.

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August 18, 2014

Gina McCarthy
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VIA ELECTRONIC MAIL

RE: Comments of the Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association and the Virginia Oil and Gas Association -- Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Docket ID No. EPA-HQ-OAR-2010-0505.

Dear Administrator McCarthy:

The Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association, and the Virginia Oil and Gas Association (collectively, the "Independent Producers") appreciate the opportunity to submit comments on the proposed rule entitled "Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards" ("Proposed Rule") and published in the Federal Register on July 7, 2014 (79 Fed. Reg. 41752).

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV") is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia, and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong,

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competitive and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of the state.

The Kentucky Oil & Gas Association, Inc. ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators, as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Through the years PIOGA's membership has grown to nearly 1,000 members: oil and natural gas producers, drilling contractors, service companies, engineering companies, manufacturers, marketers, Pennsylvania Public Utility Commission-licensed Natural Gas Suppliers ("NGSs"), professional firms and consultants, and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations in both conventional geologic formations and unconventional shale formations, and the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Indiana Oil and Gas Association, Inc. ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering, and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does, and will affect the business of this industry

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

Formed in 1977 the Virginia Oil & Gas Association ("VOGA") is a non-profit trade association representing the interests of companies, partnerships, individuals, or other entities having an interest in the oil and gas industry and who are primarily engaged in the exploration, production, development, transportation, and distribution of natural gas and oil in Virginia.

The above associations came together, in large part, to comment on the original rule (individually, or as a member of IPAA), published on August 16, 2012; petition the United States Environmental Protection Agency ("USEPA") for reconsideration on October 15, 2012; and file a legal challenge in the United States Court of Appeals for the District Circuit to the August 16, 2012 final rule because there are aspects of the final rule and Proposed Rule that disproportionally impact conventional wells and energized wells – particularly as it relates to reduced emission completions ("RECs"). The history and activities of the above associations are relevant because of the depth of knowledge and unique position that many of their members have within the industry. The Independent Producers appreciate that the USEPA has recognized the proposed definition of a "low pressure well" proffered by the Independent Producers, but we are concerned that the USEPA continues to misunderstand our concerns and has not justified its definition of a low pressure well.

USEPA's preamble discussion of the low pressure well definition misses the point. It states in relevant part:

> [T]he three parameters discussed above and used in the EPA definition are known by operators in advance of flowback and that the relatively simple calculation called for in the EPA definition could be performed with a basic hand-held calculator and should not pose difficulty or hardship for the smaller operators.

79 Fed. Reg. 41758. The "hardship" is not the calculation. The hardship is being required to perform RECs on marginally cost-effective wells that industry has historically recognized as low pressure wells. While the ultimate calculation may be completed on a "basic hand-held calculator," it does not mean that the derivation of the formula or the results of the calculation accurately depicts what constitutes a low pressure well.

Additionally, the preamble takes issue with the Independent Producers petition for reconsideration because it "did not include any details on which of EPA's assumptions is questionable . . . ." *Id.* While we provide details in these comments, USEPA's statement requires that we emphasize that the burden to justify the rule is on USEPA, not the Independent Producers or any other commenters. One of the key assumptions to the USEPA's definition is its reliance on the Turner equation to calculate the minimum gas velocity needed to lift a droplet.[1] This equation is used to predict the velocity needed to lift to the surface the proppant used to hydraulically fracture the well. The Turner equation is from a 1969 article in the Oil and Gas Journal.[2] The equation is based on a droplet reversal model. Independent Producers are not aware of the oil and gas industry using the Turner equation for any practical applications (unlike Independent Producers' proposed definition which relies on industry accepted calculations).

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[1] Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Supplemental Technical Support Document for the Final New Source Performance Standards, pp. 34-37 (April 2012).

[2] Turner, R. G., *et. al.*, *Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells*, Journal of Petroleum Technology, Nov. 1969, Equation 4, at 1476.

Independent Producers site a *recent* engineering doctoral dissertation at the Tulsa University that compared several methods of calculating liquid loading in a well, which it is relevant as it pertains to the equations used by USEPA to develop a definition of a low pressure well. The dissertation was delivered by Dr. Shu Luo, a graduate student at Tulsa University, in 2013. His advisor was Dr. Mohan Kelkar, head of the Petroleum Engineering Department. Dr. Lho's abstract follows.

> When natural gas is produced from gas wells, it is always accompanied by liquid. At the later stages of a well's life, the gas is unable to carry liquid to the surface, resulting in liquid accumulation at the bottom of the well; this is called "Liquid Loading". Knowing when the liquid loading will occur is important because by using certain artificial lift methods the well can be produced under stable conditions even after the transition. The most popular method in the literature for determining the onset of liquid loading is the equation developed by Turner et al. This equation is a droplet model and is based on the terminal velocity of liquid droplet in single phase gas column. Many modifications have been proposed to this equation to improve the prediction of liquid loading. Recently, Veeken et al. have shown that in many inclined and some vertical wells, Turner's equation under-predicts the true critical flow rate (the flow rate at which liquid loading starts). This may be due to angle of deviation as well as the fact that inception of liquid loading is more likely due to liquid film reversal in annular flow rather than droplet fall back.
>
> In this dissertation, the inception of liquid loading is defined using the liquid film reversal model based on experimental observation. Also, a new liquid loading model which is based on liquid film reversal is proposed. We base our model on Barnea's model and make several improvements to that model for better prediction of liquid loading. The improvements include: (i) development of variable film thickness model to account for the deviation angle of the well; (ii) development of equation to account for annular flow; and (iii) improvement of the friction factor equation at the interface between the liquid film and the gas core. We validated our model against all the available data from the literature as well as additional data collected from various operators. The results show remarkable improvement over Turner's original method as well as various ad hoc modifications made to that equation. A method which determines the unloading of a gas well after shut in will also be discussed.
>
> In this dissertation, we also explore one possible method to eliminate liquid loading. Injection of surfactant is one of the common methods used for avoiding liquid loading in gas well. Using our definition of liquid loading, the stability of foam flow can be predicted. We also propose a correlation for liquid holdup in foam flow and compare the predictions with experimental data. Based on the large scale experimental data, we

> provide a preliminary model for predicting foam flow and articulate reasons why the foam works in preventing liquid loading.[3]

In relevant part, according to the recent research, the Turner equation typically under-predicts the velocity necessary to unload the well. Since the Turner equation under-predicts velocity, the resulting USEPA low pressure well formula then also under-predicts the pressure necessary for a well to flowback without assistance. For instance, to increase velocity in the well tubing, which has a fixed flow area, the flow rate of gas must be increased to carry the liquid up the tubing. To increase the flow rate within a given pipe size, pressure must increase. Operators will sometimes install smaller tubing to decrease flow area, which also increases velocity. This is one example of where USEPA's derivation of a complex equation to define low pressure well is flawed. A more accurate low pressure well definition should rely on the liquid film reversal model versus the Turner equation, and result in a higher pressure threshold than currently proposed by the USEPA. Again, the burden is on USEPA to justify its definition and not to simply question the alternative definition proposed by the Independent Producers. USEPA's reliance on an outdated equation not recognized or utilized by the industry is inappropriate.

As to the Independent Producers' alternative definition of a low pressure well, Independent Produce proposed the following more simple definition for "low pressure well."

> "A well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flow-back period will be less than three days in duration."

This definition was based on the weight of fresh water (8.33 lbs/gal) which is stacked on top of itself, and is known as hydrostatic pressure. Converting the density of fresh water to a pressure gradient results in 8.33 lb/gal being equal to 0.433 psi/ft. Therefore, the pressure of fresh water in the well bore is 0.433 psi/ft times the vertical well depth.

In reality, the fluid flowing to the surface could be fresh water, re-used hydraulic fracturing water, re-used produced water, or a mixture. Additionally, in the beginning of the operation, the initial fluids flowing to the surface are essentially the fracturing fluids put down hole. At the end of the operation, the fluids flowing to the surface will mainly consist of reservoir fluids, and the water will be more of a brine water and not fresh water. Brine water has a greater density, and more reservoir pressure will be required to lift the fluid to the surface. The use of a fresh water gradient of 0.433 psi/ft should be used to keep the definition conservative and simple.

As an alternative – or in addition – to a fresh water gradient, the density of brine water influenced by sand or proppant should be used to more accurately reflect the pressure of the water column in the well bore. In fact, USEPA appears to have utilized a gradient of 0.4645 psi/ft in the "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions

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[3] Luo, Shu, Inception of liquid loading in gas wells and possible solutions, Ph.D. diss., The University of Tulsa, 2013.

Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[4] This is evidenced by the gradients listed in Exhibit 5 of the paper. A copy of this paper is provided as Attachment 1. Additionally, to perform a REC, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure for it to get into the natural gas gathering line. To combust flowback emissions, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure to flow to a flare or enclosed combustion device.

To reflect these realities, Independent Producers proposes to the USEPA that no emission control be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir."

At reservoir pressures below this value, enough pressure does not exist for any gas to flow to a flare, enclosed combustion device or the process. Consequently, the Independent Producers propose to the USEPA that combustion through a flare or enclosed combustion device be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir plus the gathering or sales line pressure."

At reservoir pressures less than the sum of the water column pressure and the sales line pressure, the recovered gas will not naturally flow into the sales line. The Proposed Rule does not require compression of recovered gas into the sales line. USEPA has recognized this type of simpler approach in estimating the level of pressure necessary for recovered gas to flow into a gathering or sales line in their "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[5] In this paper, USEPA provides a table (Exhibit 5) with pressures necessary for various well depths. For instance, USEPA indicates that the reservoir pressure necessary to flow recovered gas into a sales line for a 10,000-foot well would be 4,645 psig plus the sales line pressure.

The definition of a low pressure well is relevant to the revised stages of flowback and helps illustrate the problem and concern of those drilling low pressure wells. The Independent Producers generally support USEPA's proposed definitions for the stages of flowback from a

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[4] USEPA; Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells; 2011. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf
[5] *Id.*

well. In the USEPA proposal for the second round of reconsideration rulemaking,[6] three (3) new terms are proposed:

- Initial flowback stage
- Separation flowback stage
- Production stage

During the initial flowback stage, USEPA has indicated that there is not enough gas to operate a separator. Gas generated during the initial flowback stage would not be controlled under the proposal. USEPA acknowledges that during the separation flowback stage there may not be enough gas to operate a separator, with the gas either combusted or recovered depending on the well type according to the proposal. For certain lower pressure wells (that most likely would not meet the USEPA proposed definition of a low pressure well), the overall flowback period (all three stages) is so short that there is an insufficient amount of gas generated during the separation flowback stage to be able to operate or utilize a separator for a meaningful time period.

The Independent Producers proposed definition of a low pressure well that focused on the "three day" flowback period attempted to recognize this point. The dynamics of most vertical wells and energized wells are such that RECs or combustion by way of a separator is not feasible. The Independent Producers request that USEPA address this issue in their final rule to acknowledge that not every well will have the three flowback stages clearly defined, and in certain instances, the separation flowback stage is so short that RECs are not feasible or required, *i.e.*, that a well can essentially go from the initial flowback state to the production stage. There is a subjective element to this evaluation, which USEPA has acknowledged, so the final rule should not prevent those drilling low pressure wells from continuing their operations. As noted before in various comments, the economic incentive to undertake RECs exists. USEPA's proposed low pressure well definition forces controls on a segment of the industry that have no or minimal beneficial impact on the environment while imposing significant additional costs that will make drilling and operating such wells uneconomical. The Independent Producers request that the definition of a low pressure well be revised as suggested above or that USEPA acknowledge the separation flowback stage can be so short in duration that RECs are not necessary.

In addition to the comments above, the Independent Producers support and incorporate by reference the comments file by the American Exploration and Production Council ("AXPC")[7] on this proposed rule.

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[6] Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Proposed Rule, 79 Fed. Reg. 41752 (July 17, 2014).

[7] AXPC is a national trade association representing 34 of the largest United States independent natural gas and crude oil exploration and production companies.

If the USEPA has any questions or concerns regarding the comments, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Bruce Moore
Amy Branning
Lee Fuller, IPAA Vice President of Government Relations
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Lou D'Amico, PIOGA Executive Director
Thomas A. Stewart, OOGA Executive Vice President
Matt Stone INOGA President
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Greg Kozera, VOGA President

ATTACHMENT 1

Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells

Executive Summary

In recent years, the natural gas industry has developed more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Industry reports that hydraulic fracturing is beginning to be performed in some conventional gas reservoirs as well. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and therefore methane emissions to the atmosphere. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990 - 2009* estimates that 68 billion cubic feet (Bcf) of methane are vented or flared annually from unconventional completions and workovers.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of thirteen different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2009 emissions reductions from RECs (as reported to Natural Gas STAR) have increased from 200 MMcf (million cubic feet) to over 218,000 MMcf. Capturing an additional 218,000 MMcf represents additional revenue from natural gas sales of over $1.5 billion from 2000 to 2009 (assuming $7/Mcf gas prices).

Technology Background

High demand and higher prices for natural gas in the U.S. have resulted in increased drilling of new wells in more expensive and more technologically challenging unconventional gas reservoirs, including those in low porosity (tight) formations. These same high demands and

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf)	Value of Natural Gas Savings ($)			Additional Savings ($)	Implementation Cost ($)	Other Costs ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf				$3 per Mcf	$5 per Mcf	$7 per Mcf
Purchased REC Equipment Annual Program	270,000 per year	$810,000 per year	$1,350,000 per year	$1,890,000 per year	$175,000 per year	$500,000	$121,250 per year	6	4	3
Incremental REC Contracted Service	10,800 per completion	$32,400 per completion	$54,000 per completion	$75,600 per completion	$6,930 per completion	$32,400	$600 per completion	Imme-diate	Imme-diate	Imme-diate

General Assumptions:
[a] Assuming 9 days per completion, 1,200 Mcf gas savings per day per well, 11 barrels of condensate recovered per day per well, and cost of $3,600 per well per day for contracted services.
[b] Assuming $70 per barrel of condensate.
[c] Based on an annual REC program of 25 completions per year.

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prices also justify extra efforts to stimulate production from existing wells in tight reservoirs where the down-hole pressure and gas production rates have declined, a process known as well workovers or well-reworking. In both cases, completions of new wells in tight formations and workovers of existing wells, one technique for improving gas production is to fracture the reservoir rock with very high pressure water containing a proppant (generally sand) that keeps the fractures "propped open" after water pressure is reduced. Depending on the depth of the well, this process is carried out in several stages, usually completing one 200- to 250-foot zone per stage.

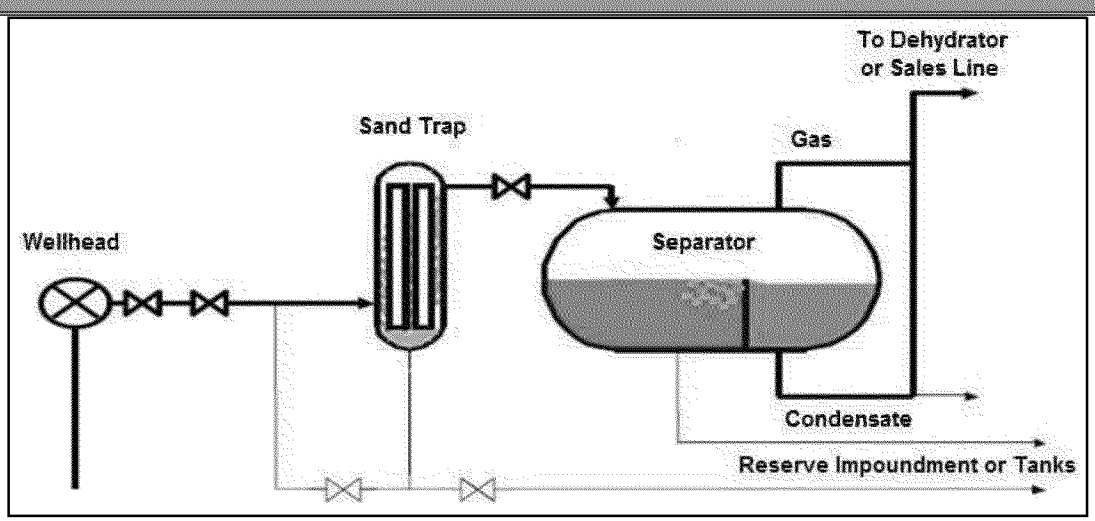
These new and "workover" wells are completed by producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared. Testing of production levels occurs during the well completion process, and it may be necessary to repeat the fracture process to achieve desired production levels from a particular well.

Natural gas lost during well completion and testing can be as much as 25 million cubic feet (MMcf) per well depending on well production rates, the number of zones completed, and the amount of time it takes to complete each zone. This gas is generally unprocessed and may contain volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) along with methane. Flaring gas may eliminate most methane, VOC and HAP emissions, but open flaring is not always a preferred option when the well is located near residential areas or where there is a high risk of grass or forest fires. Moreover, flaring may release additional carbon dioxide and other criteria pollutants (SOx, NOx, PM and CO) to the atmosphere.

Natural Gas STAR partners have reported performing RECs that recover much of the gas that is normally vented or flared during the completion process. This involves installing portable equipment that is specially designed and sized for the initial high rate of water, sand, and gas flowback during well completion. The objective is to capture and deliver gas to the sales line rather than venting or flaring this gas.

Sand traps are used to remove the finer solids present in the production stream. Plug catchers are used to remove any large solids such as drill cuttings that could damage the other separation equipment. The piping configuration to the sand traps is critical as the abrasion from high velocity water and sand can erode a hole in steel pipe elbows, creating a "washout" with water, sand,

Exhibit 1: Reduced Emissions Completion Equipment Layout



Adapted from BP.

hydrocarbon liquids and gas in an uncontrolled flow to the pad. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline. The gas may be routed to the permanent glycol unit for dehydration or a portable desiccant/glycol dehydrator used for dehydration during the completion process.

Free water and condensate are removed from the gas in a three phase separator. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. Temporary piping may be used to connect the well to the REC skid and gathering system if the permanent piping is not yet in place. Exhibit 1 shows a typical layout of temporary REC portable equipment, and Exhibit 2 explains some alternate, emerging, and/or experimental procedures for a well completion and REC.

Exhibit 2: Alternate Completion Procedures

Energized Fracturing

Based on Natural Gas STAR partner experiences, RECs can also be performed in combination with energized fracturing, wherein inert gas such as CO_2 or nitrogen is mixed with the frac water under high pressure to aid in the process of fracturing the formation. The process is generally the same with the additional consideration of the composition of the flowback gas. The percent of inert gases in the flowback gas is, at first, unsuitable for delivery into the sales line. As the fraction of inerts decreases, the gas can be recovered economically. A portable membrane acid gas separation unit can further increase the amount of methane recovered for sales after a CO_2 energized fracture.

Compression

Two compressor applications during an REC have been identified or explored by Natural Gas STAR partners.

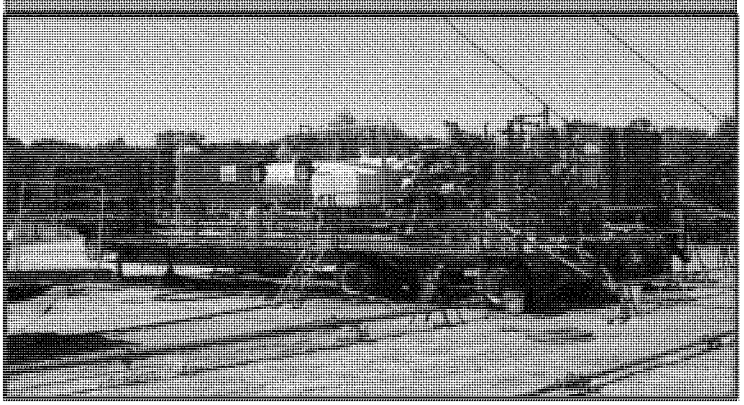
1) Gas Lift. In low pressure (i.e. low energy) reservoirs RECs are often carried out with the aid of compressors for gas lift. Gas lift is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the frac fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during an REC.

2) Boost to Sales Line. When the gas recovered in the REC separator is lower pressure than the sales line, some companies are experimenting with a compressor to boost flowback gas into the sales line. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate. Coal bed methane well completion is an example where additional compression might be required.

The equipment used during RECs is only necessary for the time it takes to complete the well; therefore, it is essential that all the equipment can be readily transported from site to site to be used in a number of well completions. A truck mounted skid, as shown in Exhibit 3, is ideal for transporting the equipment between sites. In a large basin that has a high level of drilling activity it may be economic for a gas producer to build its own REC skid. Most producers may prefer contracting a third party service to perform completions.

When using a third party to perform RECs, it is most cost effective to integrate the scheduling of completions with the annual drilling program. Well completion time is another factor to consider for scheduling a contractor for RECs. Some well completions, such as coal bed methane, may take less than a day. On the other hand, completing wells which fracture various zones, such as shale gas wells, may take several weeks to complete. For most wells, it takes about 3 to 10 days to perform a well completion following a hydraulic fracture, based on partner experiences.

Exhibit 3: Truck Mounted Reduced Emissions Completion Equipment



Source: Weatherford

Economic and Environmental Benefits

- Gas recovered for sales
- Condensate recovered for sales
- Reduced methane emissions

- Reduced loss of a valuable hydrocarbon resource
- Reduced emissions of criteria and hazardous air pollutants

Emissions from well completions can contribute to a number of environmental problems. Direct venting of VOCs can contribute to local air pollution, HAPs are deemed harmful to human health, and methane is a powerful greenhouse gas that contributes to climate change. Where it is safe, flaring is preferred to direct venting because methane, VOCs, and HAPs are combusted, lowering pollution levels and reducing global warming potential (GWP) of the emissions as CO_2 from combustion has a lower GWP than methane. RECs allow for recovery of gas rather than venting or flaring and therefore reduce the environmental impact of well completion and workover activities.

RECs bring economic benefits as well as environmental benefits. The incremental costs associated with the rental of third party equipment for performing RECs can be offset by the additional revenue from the sale of gas and condensate. As this technology is being perfected and equipment becomes commonplace, the revenues in gas and condensate sales often exceed the incremental costs.

Decision Process

Step 1: Evaluate candidate wells for Reduced Emissions Completions.

When setting up an annual RECs program it is important to examine the characteristics of the wells that are going to be brought online in the coming year. Wells in conventional reservoirs that do not require a reservoir fracture (frac job) and will produce readily without stimulation can be cleared of drilling fluids and connected to a production line in a relatively short period of time with minimal gas venting or flaring, and therefore usually do not economically justify REC equipment. Wells that undergo energized fracture using inert gases require special considerations because the initial produced gas captured by the REC equipment would not meet pipeline specifications due to the inert gas content. However, as the amount of inerts decreases, the quality of the gas will likely meet pipeline specifications. In the case of CO_2 energized fracks, the use of portable acid gas removal membrane separators will improve gas quality and make it possible to direct gas to the pipeline (see Partner Experiences section for more information).

Decision Process
Step 1: Evaluate candidate wells
Step 2: Determine costs
Step 3: Estimate savings
Step 4: Evaluate economics

State and Local Regulations
The States of Wyoming and Colorado have regulations requiring the implementation of "flareless completions". Operators of new wells in this region are required to complete wells without flaring or venting. These completions have reduced flaring by 70 to 90 percent.

For more information, visit:
http://deq.state.wy.us
http://www.cdphe.state.co.us

Exploratory and delineation wells in areas that do not yet have sales pipelines in close proximity to the wells are not candidates for RECs as the infrastructure is not in place to receive the recovered gas. In depleted or low pressure fields with low energy reservoirs, implementing a RECs program would most likely require the addition of compression to overcome the sales line pressures–an approach that is still under development and may add significant cost to implementation.

Wells that require hydraulic fracturing to stimulate or enhance gas production may need a lengthy completion, and therefore are good candidates for RECs. Lengthy completions mean that a significant amount of gas may be vented or flared that could potentially be recovered and sold for additional revenue to justify the additional cost of a REC. If newly drilled wells are in close proximity, they could share the REC equipment to minimize transport, set-up, and equipment rental costs.

Selecting a Basis for Costs and Savings
- Estimate the number of producing gas wells that will be drilled in the next year
- Evaluate well depth and reservoir characteristics
- Determine whether additional equipment is necessary to bring recovered gas up to pipeline specifications
- Estimate time needed for each completion

Step 2: Determine the costs of a REC program.

Most Natural Gas STAR partners report using third party contractors to perform RECs on wells within their producing fields. It should be noted that third party contractors are also often used to perform traditional well completions. Therefore, the economics presented deal with

incremental costs to carry out RECs versus traditional completions.

Generally, the third party contractor will charge a commissioning fee for transporting and setting up the equipment for each well completion within the operator's producing field. Some RECs vendors have their equipment mounted on a single trailer while others lay down individual skids that must be connected with temporary piping at each site. The incremental cost associated with transportation between well sites in the operator's field and connection of the REC equipment within the normal flowback piping from the wellhead to an impoundment or tank is generally around $600/completion.

In addition to the commissioning fee, there is a daily cost for equipment rental and labor to perform each REC. As mentioned above, when evaluating the costs of well completions, it is important to consider the incremental cost of a REC over a traditional completion rather than focusing on the total cost. REC vendors and Natural Gas STAR partners have reported the incremental cost of equipment rental and labor to recover natural gas during completion ranging from $700 to $6,500/day over a traditional completion. Equipment costs associated with RECs will vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment such as a glycol dehydrator is already installed at the well site, REC costs may be reduced as this equipment can be used rather than bringing a portable dehydrator on-site, assuming the flow-back rate does not exceed the capacity of the equipment. Some operators report installing permanent equipment that can be used in the RECs as part of normal well completion operations, such as oversized three-phase separators, further reducing incremental REC costs. Well completions usually take between 1 to 30 days to clean out the well bore, complete well testing, and tie into the permanent sales line. Wells requiring multiple fractures of a tight formation to stimulate gas flow may require additional completion time. Exhibit 4 shows the typical costs associated with undertaking a REC at a single well.

Exhibit 4: Typical Costs for RECs

One-time Transportation and Incremental Set-up Costs	Incremental REC Equipment Rental and Labor Costs	Well Clean-up Time
$600 per well	$700 to $6,500 per day	3 to 10 days

For low energy reservoirs, gas from the sales line may be routed down the well casing to create artificial gas lift, as mentioned in Exhibit 2. Depending on the depth of the well, a different quantity of gas will be required to lift the fluids and clean out the well. Using average reservoir depths for major U.S. basins and engineering calculations, Exhibit 5 shows various estimates of the volume of gas required to lift fluids for different well depths.

A REC annual program may consist of completing 25 wells/year within a producer's operating region. Exhibit 6 shows a hypothetical example of REC program costs based on information provided by partner companies.

Exhibit 5: Sizing and Fuel Consumption for Booster Compressor

Well Depth (ft)	Pressure Required to Lift Fluids (psig)	Gas Required to Lift Fluids (Mcf)[a]	Compressor Size (horsepower)[a]	Compressor Fuel Consumption (Mcf/hr)[a]
3,000	1,319 + Sales line pressure	195 to 310	195 to 780	2 to 7
5,000	2,323 + Sales line pressure	315 to 430	400 to 1,500	3 to 13
8,000	3,716 + Sales line pressure	495 to 610	765 to 2,800	7 to 24
10,000	4,645 + Sales line pressure	615 to 730	1,040 to 3,900	9 to 33

[a] Based on sales line pressures between 100 to 1,000 psig.

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Exhibit 6: Hypothetical Example Cost Calculation of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gauge (psig)
T_s = Time required for transportation and set-up (days/well)
T_c = Time required for well clean-up (days/well)
O = Operating time for compressor to lift fluids (hr/well)
F = Compressor fuel consumption rate (Mcf/hr)
G = Gas from pipeline routed to casing to lift fluids (Mcf/well), typically used on low energy reservoirs
C_s = Transportation and set-up cost ($/well)
C_e = Equipment and labor cost ($/day)
P_g = Sales line gas price ($/Mcf)

W = 25 wells/yr
D = 8000 ft
P_s = 100 psig
T_s = 1 day/well
T_c = 9 days/well
O = 24 hr/well
F = 10 Mcf/hr
G = 500 Mcf/well (See Exhibit 5)
C_s = $600/well
C_e = $2,000/day
P_g = $7/Mcf

Calculate Total Transportation and Set-up Cost, C_{TS}

$C_{TS} = W * C_s$

C_{TS} = 25 wells/yr * $600/well
C_{TS} = $15,000/yr

Calculate Total Equipment Rental and Labor Cost, C_{EL}

$C_{EL} = W * (T_s + T_c) * C_e$

C_{EL} = 25 wells/yr * (1 day/well + 9 days/well) * $2,000/day
C_{EL} = $500,000/yr

Calculate Other Costs, C_O

$C_O = W * [(O * F) + G] * P_g$

C_O = 25 wells/yr * [(24 hr/well * 10 Mcf/hr) + 500 Mcf/well] * $7/Mcf
C_O = $129,500/yr

Total Annual REC Program Cost, C_T

$C_T = C_{TS} + C_{EL} + C_O$
C_T = $15,000/yr + $500,000/yr + $129,500/yr
C_T = $644,500/yr

Step 3: Estimate Savings from RECs.

Gas recovered from RECs can vary widely because the amount of gas recovered depends on a number of variables such as reservoir pressure, production rate, amount of fluids lifted, and total completion time. Exhibit 7 shows the range of recovered gas and condensate reported by Natural Gas STAR partners. Partners also have reported that not all the gas that is produced during well completions may be captured for sales. Fluids from high pressure wells are often routed directly to the frac tank in the initial stages of completion as the fluids are often being produced at a rate that is too high for the REC equipment. Where inert gas is used to energize the frac, the initial gas production may have to be flared until the gas meets pipeline specifications. Alternatively, a portable acid gas membrane separator may be used to recover methane rich gas from CO_2. As the flow rate of fluids drops and gas is encountered, backflow is then switched over to the REC equipment so that the gas may be captured. Gas compressed from the sales line to lift fluids (by artificial gas lift) will also be recovered in addition to the gas produced from the reservoir. The volume of gas needed to lift fluids can be estimated based on the well depth and sales line pressure. Gas saved during RECs can be translated directly into methane emissions reductions based on the methane content of the produced gas.

In addition to gas savings, valuable condensate may also be recovered from the REC three-phase separator. The amount of condensate that can be recovered during a REC is dependent on the reservoir conditions and fluid compositions. Condensate may also be lost if fluids are produced directly to the frac tank before switching to the REC equipment.

Exhibit 7: Ranges of Gas and Condensate Savings

Produced Gas Savings (Mcf/day/well)	Gas-Lift Savings (Mcf/well)	Condensate Savings (bbl/day/well)
500 to 2,000	See Exhibit 5	Zero to several hundred

Exhibit 8 shows typical values of gas and condensate savings during the REC process.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Step 4: Evaluate REC economics.

The example application of an REC program to 25 wells within a producing field can yield a total theoretical revenue of $2,152,500 based on the assumptions listed above from the sale of natural gas and condensate. Equipment rental, labor, and other costs associated with implementing this program are estimated to be $644,500 (see Exhibit 6) resulting in an annual theoretical profit of $1,508,000. To maintain a profitable REC program, it is important to move efficiently from well to well within a producing field so that there is little down time when paying for equipment rental and labor. Other factors that affect the profitability of an REC program include the amount of condensate recovery and sales price, the need for additional compressors, the amount of gas recovered, and gas sales price.

Exhibit 9 shows a five year cash flow projection for carrying out a 25 well per year REC program. In this example, the equipment necessary to perform RECs has been purchased by the operator rather than using a third party contractor to perform the service. The capital cost of a simple REC set-up without a portable compressor has been reported by British Petroleum (BP) to be $500,000.

Producers with high levels of localized drilling and workover activity may benefit from constructing and operating their own REC equipment. As illustrated above, even though large capital outlay is required to construct a REC skid, a high rate of return can be achieved if the equipment is in continuous use. If the operator is unable to keep the equipment busy on their own wells, they may

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Exhibit 8: Savings of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gage (psig)
S_p = Produced gas savings (Mcf/day)
T_c = Time recovered gas flows to sales line in days (days/well)
S_c = Condensate savings (bbl/well)
G = Gas used to lift fluids (Mcf/well), typically used on low energy reservoirs
P_g = Sales line gas price ($/Mcf)
P_l = Natural gas liquids price ($/bbl)

W = 25 wells/yr
D = 8000 ft
P_s = 100 psig
S_p = 1,200 Mcf/day
T_c = 9 days/well
S_c = 100 bbl/well
G = 500 Mcf/well (See Exhibit 5)
P_g = $7/Mcf
P_l = $70/bbl

Calculate Produced Gas Savings

$S_{PG} = W * (S_p * T_c) * P_g$

S_{PG} = 25 wells/yr * (1,200 Mcf/day * 9 days/well) * $7/Mcf
S_{PG} = $1,890,000/yr

Calculate Other Savings

$S_O = W * [(G * P_g) + (S_c * P_l)]$

S_O = 25 wells/yr * [(500 Mcf/well * $7/Mcf) + (100 bbl/well * $70/bbl)]
S_O = $262,500/yr

Total Savings, S_T

$S_T = S_{PG} + S_O$
S_T = $1,890,000/yr + $262,500/yr
S_T = $2,152,500/yr

contract it out to other operators to maximize usage of the equipment.

When assessing REC economics, the gas price may influence the decision making process; therefore, it is important to examine the economics of undertaking a REC program as natural gas prices change. Exhibit 10 shows an economic analysis of performing the 25 well per year REC program in Exhibit 8 at different gas prices.

Exhibit 9: Economics for Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Volume of Natural Gas Savings (Mcf/yr)[a]		270,000	270,000	270,000	270,000	270,000
Value of Natural Gas Savings ($/year)[a]		1,890,000	1,890,000	1,890,000	1,890,000	1,890,000
Additional Savings ($/yr)[a]		175,000	175,000	175,000	175,000	175,000
Set-up Costs ($/yr)[b]		(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Equipment Costs ($)[b]	(500,000)					
Labor Costs ($/yr)[c]		(106,250)	(106,250)	(106,250)	(106,250)	(106,250)
Net Annual Cash Flow ($)	**(500,000)**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**

Internal Rate of Return = 389%
NPV (Net Present Value)[d]= $6,243,947
Payback Period = 3 months

[a] See Exhibit 8.
[b] See Exhibit 6.
[c] Labor costs for purchased REC equipment estimated as 50% of Equipment Rental and Labor costs in Exhibit 3.
[d] Net present value based on 10% discount rate over five years.

Exhibit 10: Gas Price Impact on Economic Analysis of Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Gas Price				
	$3/Mcf	**$5/Mcf**	**$7/Mcf**	**$8/Mcf**	**$10/Mcf**
Total Savings	$985,000	$1,525,000	$2,065,000	$2,335,000	$2,875,000
Payback (months)	7	5	4	3	3
IRR	172%	280%	389%	443%	551%
NPV (i = 10%)	$2,522,084	$4,383,015	$6,243,947	$7,174,413	$9,035,345

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Partner Experience

This section highlights specific experiences reported by Natural Gas STAR partners.

BP Experience in Green River Basin

- Implemented RECs in the Green River Basin of Wyoming
- RECs performed on 106 wells, which consisted of high and low pressure wells
- Average 3,300 Mcf of natural gas sold versus vented per well
  - Well pressure will vary from reservoir to reservoir
  - Reductions will vary for each particular region
  - Conservative net value of gas saved is $20,000 per well
- Natural gas emission reductions of 350,000 Mcf in 2002
- Total of 6,700 barrels of condensate recovered per year total for 106 wells
- Through the end of 2005, this partner reports a total of 4.17 Bcf of gas and more than 53,000 barrels of condensate recovered and sold rather than flared. This is a combination of activities in the Warmsutter and Jonah/Pinedale fields.

Noble Experience in Ellis County, Oklahoma

- Implemented RECs on 10 wells using energized fracturing.
- Employed membrane separation in which the permeate was a CO_2 rich stream that was vented and the residue was primarily hydrocarbons which were recovered.
- Total cost of $325,000.
- Total gas savings of approximately 175 MMcf.
- Estimated net profits to be $340,000
- For more information, see the Partner Profile Article in the Spring 2011 Natural Gas STAR Partner Update available at: http://epa.gov/gasstar/newsroom/partnerupdatespring2011.html

Partner Company A

- Implemented RECs in the Fort Worth Basin of Texas
- RECs performed on 30 wells, with an incremental cost of $8,700 per well
- Average 11,900 Mcf of natural gas sold versus vented per well
  - Natural gas flow and sales occur 9 days out of 2 to 3 weeks of well completion
  - Low pressure gas sent to gas plant
  - Conservative net value of gas saved is $50,000 per well
- Expects total emission reduction of 1.5 to 2 Bcf in 2005 for 30 wells

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Lessons Learned

- Incremental costs of recovering natural gas and condensate during well completions following hydraulic fracturing result from the use of additional equipment such as sand traps, separators, portable compressors, membrane acid gas removal units and desiccant dehydrators that are designed for high rate flowback.
- During the hydraulic fracture completion process, sands, liquids, and gases produced from the well are separated and collected individually. Natural gas and gas liquids captured during the completion may be sold for additional revenue.
- Implementing a REC program will reduce flaring which may be a particular advantage where open flaring is undesirable (populated areas) or unsafe (risk of fire).
- Wells that do not require hydraulic fracturing are not good candidates for reduced emissions completions. Methane emissions reductions achieved through performing RECs may be reported to the Natural Gas STAR Program unless RECs are required by law (as in the Jonah-Pinedale area in WY).

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2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

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May, 28, 21013

The Honorable Bob Perciasepe, Acting Administrator
U.S. Environmental Protection Agency
EPA West (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Attention: Docket ID Number EPA-HQ-OAR-2010-0505
Submitted via email to *a-and-r-docket@epa.gov*

RE: Comments of the Independent Petroleum Association of America on "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 Fed.Reg. 22126 (Apr. 12, 2013). Docket ID No. EPA-HQ-OAR-2010-0505

Dear Acting Administrator Perciasepe:

The Independent Petroleum Association of America ("IPAA") appreciates the opportunity to provide comments on the United States Environmental Protection Agency's ("EPA") rulemaking entitled "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 Fed. Reg. 22,126 (April 12, 2013). IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be the most significantly affected by these proposed regulatory actions. Independent producers develop 95 percent of domestic oil and gas wells, produce 68 percent of domestic oil and produce 82 percent of domestic natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

IPAA believes the majority of the proposed revisions are beneficial to the industry while still protective of the environment. IPAA looks forward to working with EPA to further improve the rule. IPAA also appreciates EPA's willingness to expedite this rulemaking in light of the pending October 15, 2013 compliance deadline for the storage vessel requirements under 40 C.F.R. Part 60 Subpart OOOO. IPAA believes collaboration between the agency and the regulated community will result in workable regulations that are both cost-effective and protective of the environment.

As further discussed later in these comments, IPAA generally supports the following proposed amendments to the existing requirements for storage vessels:

- IPAA supports breaking down storage vessel affected facilities into two categories (i.e., "Group 1" and "Group 2" tanks) to help reduce the demand for control devices and service providers, as well as the proposed extension of the compliance deadline for implementing controls to April 15, 2014. The potential for a shortage of equipment and service providers—even with the extended deadline—remains real for many of the smaller independent producers with less leverage and buying power.
- IPAA strongly supports the proposed streamlined provisions related to continuous compliance demonstration and monitoring requirements during the reconsideration period. IPAA requests that the streamlined provisions be proposed for adoption as the final compliance and monitoring requirements in the anticipated rulemaking to address additional reconsideration issues (expected proposal in December 2013).
- IPAA supports the concept of an alternative mass-based limit for uncontrolled emissions and the ability to remove controls if emissions are demonstrated to fall below an established threshold for a set period of time. Although IPAA appreciates that EPA believes it is inappropriate for the alternative mass-based limit to be the same as the applicability threshold, EPA has failed to provide a reasoned or rational basis for its position. EPA initially justified controls on storage vessels as cost effective at 6 tons per year ("TPY") – not 4 TPY. IPAA believes the alternative mass-based limit should be 6 TPY.
- IPAA supports extending the time period for the submittal of annual reports and compliance certifications from 30 days to 90 days after the end of the given compliance period.
- IPAA supports EPA's effort to align the test protocols for combustion control devices for the NSPS with those found in the applicable National Emission Standards for Hazardous Air Pollutants and the provisions which provide for manufacturer testing provisions that allow for certification of certain specific devices.
- IPAA supports the clarification of the definitions of "storage vessel" and "storage vessel affected facility."

In addition to generally supporting the proposed amendments discussed above, IPAA provides the following comments and suggestions that it believes will further improve the final provisions of the rule.

1. As currently proposed, Group 1 storage vessels are required to comply with certain additional provisions if there is an "event that could reasonably be expected to increase VOC emissions . . . ." 40 C.F.R. § 60.5395(b). The subsection cites the following four "examples" of events, indicating the list is not exhaustive: (i) routing an additional well to the storage vessel that was not previously routed to the vessel, (ii) conducting fracturing on a well routed to the storage vessel, (iii) conducting refracturing on a well routed to the storage vessel, and (iv) any other event that could increase the VOC emissions from the storage vessel affected facility. *Id.* § 60.5395(b)(2)(i)-(iv). IPAA believes the definition of "event" should be limited to the first three examples, as the fourth "example" is so broad and subjective as to provide no clarification whatsoever. To the extent that EPA is unwilling to limit the examples of qualifying "events," the fourth example should be revised to read "any other event that could **reasonably be expected to** increase the VOC emissions from the storage vessel affected facility."

2. As currently proposed, owners and operators of Group 2 storage vessels must determine their VOC emissions by April 15, 2014 or 30 days after startup, whichever is later. *Id.* § 60.5395(c)(1) and (2). If VOC emissions are projected to be equal or greater than 6 TPY, then controls must be installed by April 15, 2014 or 60 days after startup, whichever is later. *Id.* § 60.5395(d). These time periods are simply too short. At a minimum, **90 days** is necessary to conduct the required emissions calculation and install controls. The first 30 days of production normally are not representative of stabilized production from a well, and are subject to variation that could result in the overestimation **or** underestimation of the emissions from storage vessels associated with that well. Thus, at least 45 days is needed to evaluate and accurately calculate projected annual emissions from a storage vessel. Another 45 days—again, at a minimum—would be needed to engage a contractor and install the necessary controls. Providing a total of 90 days to make the initial emissions determination **and** install any necessary controls will ensure a more reliable emissions estimate and afford the regulated community sufficient time to contract for the testing/modeling of emissions and installation of controls. Accordingly, IPAA recommends that EPA extend this compliance period to 90 days.

3. If EPA is unwilling to provide 90 days for operators to conduct their emissions determinations and install necessary controls as requested in Comment No. 2 above, IPAA believes it is appropriate to consider differentiating between storage vessels located at new facilities (or at existing facilities not subject to air quality permitting) versus storage vessels at existing, currently permitted facilities. The primary methodology for projecting emissions from storage vessels involves hiring an outside contractor to visit the site, sample the condensate/liquid, conduct laboratory analysis to generate the condensate characteristics, and then calculate emissions based upon the throughput of the vessel. The logistics of retaining and then scheduling the contractor to perform this work takes time, and there will be instances that producers—especially independent producers—will not likely be able to comply with the 30-day emissions determination for reasons beyond their control (i.e., they could not get a service provider out to the storage vessel in time). Similar issues can arise with regard to the installation of emissions controls. Storage vessels at existing affected facilities with air quality permits within the same formation or drilling characteristics are more likely to have relevant emissions modeling associated with the condensate/liquid produced from the well(s). Consequently, projecting annual emissions should be less time-consuming for these facilities, although IPAA believes that a 60-day compliance period for facilities with existing emissions data on condensate/liquids is necessary to provide the flexibility needed to align contractors for installation of controls. The importance of this issue for independent producers cannot be overstated. The lack of access to or ability to timely contract with service providers will place many of the smaller independent producers at serious risk of noncompliance, through no fault of their own.

4. If EPA is unwilling to adopt a permanent distinction between storage vessels at new and existing affected facilities as advocated in Comment No. 3 above, IPAA suggests that EPA institute an extended compliance period for vessels at new facilities for a period of two years. This will reduce the likelihood that independent producers will be exposed to enforcement due to the lack of available equipment and service providers, while continuing

to ensure that emissions reductions occur in a timely fashion. IPAA encourages EPA to strike an appropriate balance between achieving emissions reductions and the practical realities associated with limited supply of and increased demand for equipment and service providers. Unnecessarily condensed timeframes will have limited benefit to the environment, but will create undue hardship for a segment of the industry that provides a significant portion of the natural gas produced in this country.

5. As indicated above, IPAA supports the proposal to adopt an alternative emission limit of 6 TPY for uncontrolled emissions, and the ability to remove controls if emissions are demonstrated to fall below that threshold for a period of time. As currently proposed, if uncontrolled emissions from the affected facility drop below 4 TPY for a period of 12 consecutive months, the emission controls can be removed. *Id.* § 60.5395(d)(2). If at some point after the 12 month period the emissions rise above an estimated 4 TPY, however, controls must be reinstalled. *Id.* IPAA suggests certain revisions to these provisions, which would provide the same degree of environmental protection while reducing the burden and cost of compliance. In the response to comments document associated with the final rule, EPA calculated the cost effectiveness of controls at the 6 TPY threshold to be approximately $3400 per ton. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Parts 60 and 63, Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738),* at 108-110. Commenters argued that even a TPY threshold above10 TPY would result in a prohibitively high cost effectiveness of over $5000 per ton. EPA did not dispute the commenters calculations, but merely stated that EPA felt their "different source of cost information" . . . "developed specifically for this industry . . . may be more accurate than the more generalized Control Cost Manual analysis." *Id.* Subsequent studies and reports have called into question EPA's emissions estimates associated with hydraulic fracturing. IPAA believes that EPA has failed to justify its proposed alternative mass emission limit of 4 TPY and that the alternative limit should be 6 TPY. Additionally, instead of requiring 12 months of data demonstrating uncontrolled emissions below 4 TPY, IPAA believes that six months of data demonstrating emissions below 6 TPY is sufficient. As EPA has acknowledged, emissions from the vast majority of wells continue to decline over time and seldom increase without some intervening event. Thus, six months of data below an annual emission rate of 6 TPY is more than sufficient to demonstrate that the well is in steady decline and VOC emissions will remain below the 6 TPY threshold. IPAA also suggests that the obligation to conduct monthly monitoring be discontinued after six months of data demonstrating VOC emissions below 4TPY, absent an intervening event as set forth in 40 C.F.R. § 60.5395(b)(2).

6. As discussed above in Comment No. 5, under the current proposal, controls on storage vessels would need to be reinstalled if VOC emissions increase above the 4 TPY threshold. IPAA suggests that the threshold for reinstalling controls should be the same as the 6 TPY applicability limit for storage vessels initially. EPA has not provided a reasonable basis for imposing a different applicability threshold for tanks that initially had controls on them versus "new" vessels that are evaluating applicability for the first time. For example, if an operator needs to install a storage vessel at a new well pad and has two identically sized vessels at his disposal for installation—a brand new tank that has never been "installed"

and a tank that became an affected facility because its annual emissions were at one point above 6 TPY and is no longer needed at an older well—the incentive will be to install a new storage vessel to take advantage of the higher 6 TPY threshold, despite the fact that there is absolutely no difference between the two units. The different thresholds lack a supportable basis from an environmental standpoint and create an incentive to waste resources and unnecessarily drive up costs to producers.

7. In addition to the practical limitations of basing annual emissions on the first 30 days of production, IPAA is concerned about the enforcement ramifications of inaccurately estimating annual emissions based on this period. Essentially every estimate of annual emissions will be based on projected throughput over the course of a year. Due to the inherent uncertainty in projecting the production of a given well, there should be provisions included in the regulations that provide reduced enforcement exposure if producers diligently monitor their throughput (and hence their emissions) and promptly report any errors discovered with regard to the annual emissions estimate. IPAA appreciates that EPA must create the proper incentive for operators to make every effort to estimate their annual emissions accurately at the outset. However, IPAA believes that EPA also should consider that, unlike many other industrial processes, predicting the production of a given well is not a precise science. IPAA recommends that EPA include in the final version of this rule—or propose to include in the second reconsideration rulemaking scheduled for December 13, 2013—provisions that provide operators reduced enforcement exposure if errors in annual production based emissions calculations are promptly reported (e.g., within 30 days) to EPA (or the implementing state/local authority) and appropriate controls are installed within an additional 30 days. Such notification would require an explanation of why the initial annual emissions estimate was incorrect. IPAA further understands EPA's concerns regarding establishing a precedent in terms of reduced enforcement exposure for those entities that fail to make accurate emissions estimates. Again, the lack of predictability in estimating emissions from a given well is unlike projecting emissions from operations in other industries and thus gives EPA a basis for differential treatment. EPA has acknowledged such uncertainty in the regulations associated with greenhouse gas reporting and made certain accommodations accordingly, e.g. 40 C.F.R. § 98.3 (h). IPAA would be pleased to meet with EPA to discuss potential regulations that provide the proper incentive for producers to provide emissions estimates predicted on best engineering judgment while making allowances for unforeseen circumstances which could result in errors in the initial emission estimate.

8. As indicated above, IPAA strongly supports the streamlined compliance monitoring provisions proposed to be instituted during reconsideration of issues raised in the various reconsideration petitions. The existing provisions in the current rule are unnecessary to ensure compliance and are extremely burdensome to the smaller independent operations. As proposed, the monthly inspections and obligations for prompt repairs can be accomplished with existing personnel and not significantly add to the cost of compliance while ensuring that the required emissions controls are operating properly. The reasons that EPA proposed to utilize the streamline provisions and the benefit to industry will not change when the reconsideration rulemakings come to a close. The justifications for the

streamlined provisions during the reconsideration period will continue to be valid and warrant continuation of the streamlined provisions after the reconsideration rulemaking.

9. One additional "global" revision to the rules that would greatly reduce the inspection and monitoring obligations is to allow for proof of inspection and monitoring to be kept onsite, at the relevant field office or to be made available upon request. Many affected vessels are located in extremely remote areas and protecting such records from exposure to the environment is difficult. Additionally some operators conduct inspections and monitor certain equipment electronically, and therefore do not always generate "paper copies" on location. IPAA appreciates the need to record and retain inspection and monitoring records, but dictating that hard copies be maintained onsite is not necessary and may not be the best or most feasible way to retain the important information. Providing the operators the requested flexibility would benefit industry without harming the environment or reduce EPA's ability to monitor compliance effectively.

In addition to the comments provided above, IPAA endorses the comments of AXPC and ANGA. As indicated initially, IPAA appreciates the opportunity to provide comments on the proposed rule and would be happy to have further discussion with the agency regarding the issues raised above. Please contact me or Matt Kellogg at 202.857.4722 or Jim Elliott at 202.361.8215 if you have any questions regarding these comments.

Sincerely,

Lee O. Fuller
Vice President of Government Relations
Independent Petroleum Association of America

Cc: Gina McCarthy
Peter Tsirigotis
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Submitted via email

November 30, 2011

Gina McCarthy
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Re: Oil and Natural Gas Sector Consolidated Rulemaking,
Docket ID No. EPA-HQ-OAR-2010-0505

Dear Assistant Administrator McCarthy,

The Independent Petroleum Association of America submits these comments with respect to the United States Environmental Protection Agency's (EPA) Proposed Rules entitled "*Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*", dated August 23, 2011 (76 FR 52738).

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment Suppliers Association (PESA) and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association

New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Alliance of Independent Producers
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Virginia Oil and Natural Gas Association
Western Energy Alliance

Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be the most significantly affected by these proposed regulatory actions. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 56 percent of American oil, and more than 85 percent of American natural gas.

In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. In general, we also support the comments submitted separately by the American Petroleum Institute (API), the American Exploration and Production Council (AXPC) and America's Natural Gas Alliance (ANGA). However, in some instances we believe that the proposed regulations are in such significant need of reevaluation that the only recourse is reconsideration and reproposal of regulations.

This proposed rulemaking would modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 Subparts HH and HHH. These rules are being addressed together under the auspices of EPA's sector-based rulemaking for the oil and natural gas industry. Our comments will address two aspects of the proposal: the NSPS for natural gas well completions and the NSPS for crude oil and condensate storage facilities.

In developing NSPS, EPA must meet the following definition:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

This definition includes key factors that must be addressed in an NSPS determination. It must consider cost effectiveness. It must consider energy implications. It must be adequately demonstrated for the application that will be regulated. We believe that EPA has failed to meet these requirements with regard to well completions and storage facilities. In large measure, it fails to meet these requirements because its emissions analyses are inaccurate and its application to segments of the industry fails to be adequately demonstrated and cost effective.

Well Completions

Vertical Well Issues

EPA's definition of a natural gas well completion creates a significant inequity. EPA applies its NSPS requirements to any natural gas well completion that uses hydraulic fracturing. The sweep of this definition would capture natural gas well completions that include only a vertical component and wells with both vertical and horizontal components. However, it is clear that in developing its basis for its reduced emissions completion (REC) or "green completion" technology, EPA bases its determinations on well completions with horizontal legs. Yet, EPA would require the same controls for vertical wells where the emissions would be far less.

Requiring REC on all natural gas well completions makes no sense. There are over 50 depositional basins across the United States that produce oil and natural gas. EPA has only visited a few of them. While there can be similarities in fracturing treatments within a particular formation or depositional basin, there can be big differences between basins across the country. Virtually all of the non-conventional, horizontal completions use large-volume multi-stage hydraulic fracturing treatments, while most of the conventional, vertical well fracture treatments are relatively low volume, single stage events. Applying a one-size-fits-all standard to both types of wells is counterproductive.

If REC remains an option rather than a requirement for conventional vertical natural gas wells, it will continue to be integrated naturally into the flowback process where it is cost-effective and appropriate. However, there are many circumstances where REC is not only inappropriate, but provides little or no environmental or economic benefit. The post-fracturing conditions are more diverse with conventional, vertical well completions than with non-conventional, horizontal well completions.

After a conventional, vertical well is hydraulically fractured, the reservoir pressure may not be high enough to clear the well bore of fluid. If the reservoir pressure is not high enough, the well must have pressure added to artificially help initiate, or "kick-off", return flow. One method is to use a jet pump. A jet pump is run on tubing down the hole and water is pumped down the tubing at pressures as high as 3,000 psig. Located at the bottom of the tubing, small pin holes point upward into the tubing/casing annulus. The flow of high-pressure water from these holes creates a low-pressure zone at the bottom of the well bore that helps to start the gas flowing out of the formation.

A more expensive process is to pump nitrogen down the hole to help clean out fluids remaining in the well bore. Or, liquid carbon dioxide can be used as a fracturing fluid. Both of these options make the flow-back non-combustible, so the flow-back gas cannot be sold to the pipeline or flared. Under these conditions it would not be feasible to use the REC process.

The factors that affect the characteristics of the post-fracturing flowback process vary considerably with conventional, vertical well fracture treatments. These factors include:

1 – The depth of the well;
2 – The thickness of the formations;
3 – The reservoir pressures;
4 – The type of formations;
5 – The type of fracturing fluid used (water, carbon dioxide, nitrogen);
6 – The amount (#/gal) of proppant used;
7 – The amount of treatment fluid recovered;
8 – The ability of the well to flow against the back-pressure of the fluid in the hole;
9 – The need for a jet pump to kick-off the well;
10 – The amount of time needed to clear the well;
11 – The ability to flair the flow back gas; and,
12 – The ability to sell the flow back gas.

The goal of all producers is to stop venting or flaring and start selling the natural gas as soon as possible. It is a matter of economics. If the choice of how to clean up the well after fracturing remains with the producer, REC will be implemented when economically feasible or when required for safety reasons.

The consequences would be severe for these smaller wells. Significantly, most of these vertical wells would be developed by producers many of which are small businesses. Since the natural gas well REC requirements were developed for large horizontal shale gas wells, the distinctions between horizontal wells and vertical ones are pertinent. Many smaller independents are drilling traditional vertical wells that are completed in traditional sandstone and limestone formations. The completions usually take just a few hours. Instead of treating 5,000 feet of a shale formation they are treating 30 to 100 feet of sandstone or limestone. The flowback differs from formation to formation and is usually directed into a lined pit. The goal is to clean out the sand from the well quickly and get the natural gas into the production pad separation equipment and then into the pipeline meter. With the flowback time and volume so much smaller in vertical wells, it is hard to justify separation equipment for a small amount of sand. Additional complexities depending on the nature of the particular formation can be significant.

Wells developed in Kentucky are illustrative. Producers in Kentucky report that if they were required to only perform REC on their wells the entire natural gas production industry could be halted. Currently, because of the low formation pressure on these Shale Gas reservoirs, completion stimulation is done with nitrogen. A typical fracturing process on these shale gas formations is either a "Foamed Frac" using a proppant of sand and conveyed into the formation in an energized fluid made up of mostly nitrogen, or a "Gas Frac" where nitrogen as a gas is the only material pumped down hole to break the rock. In both cases, after the stimulation treatment, the well's flowback is released to the atmosphere until the flow is clean enough to sell into the pipelines. The advantage to these types of completions is that they clean up relatively quickly, use nitrogen which is inert, and the locations needed to drill the wells are kept relatively small compared to the amount of gas bearing reservoir that is developed. No one can tell exactly how much methane is in the nitrogen released back to the atmosphere but it would likely be more than the 100 Ton (4MMcf) limit EPA proposes. Proving the amount released would be difficult and present a burden on the operator. Importantly, there is no way to separate the nitrogen from the flowback stream in order to sell the natural gas as would be required in a REC of a "non-exploratory" well. Even the alternative for "exploratory" wells, allowing the flowback stream to be flared, is not possible during most of the clean up procedure because the nitrogen

levels would be too high for the natural gas to burn. Shortly before the clean up is complete, the nitrogen levels would drop low enough that the vented gas could possibly burn, but it would need a large flare pit, which would require the clearing of many more trees in Kentucky's forested areas than are required for the drilling location.

While the Kentucky example may have some unique aspects, the application to vertical wells is far broader. As an example of impacts of this regulation on small operators, consider wells drilled in Pennsylvania (from the PA DEP website):

Year	Marcellus	Non-Marcellus	Total
2005	2	3,653	3,655
2006	11	4,175	4,186
2007	34	4,129	4,163
2008	210	4,039	4,249
2009	768	1,775	2,543
2010	1,446	1,397	2,843
2011 (to 9/31)	1,397	683	2,080

It is safe to assume that all wells were completed with hydraulic fracturing. As can be seen from the DEP statistics, since 2006, the number of Marcellus wells being drilled is rapidly increasing while the number of non-Marcellus wells and the total number of wells drilled is declining. When looking at the data over the 5-year period from 2006 through 2010, there was an average of 494 Marcellus and 3,103 non-Marcellus wells drilled per year. By considering the county locations of the oil patch and of the 3,103 average non-Marcellus wells during those same years, there were an average of 2,132 gas wells and 971 oil or combination oil and natural gas wells drilled per year. As mentioned above, these non-Marcellus natural gas wells are completed in a few hours. If natural gas collection lines have not yet been constructed, costs for these average 2,132 natural gas wells could be as high as $7.5M based on EPA cost information. If natural gas collection lines are available, and again applying EPA cost information and recognizing that these shallow, vertical, stripper gas wells (less than 60 MCF/day average production) will not produce much natural gas and condensate during flowback, the cost for these same wells could be as high as $8.8M. These estimates do not include costs for combination wells. These average costs of $3,523 to $4,146 per vertical well will make many of these wells uneconomical. These wells should be exempt from the proposed regulation.

Emissions Estimates

Regardless of the type of well, the NSPS proposal suffers from inaccurate data on emissions from natural gas well completion. From several accounts EPA's assessment of well completion emissions is based on a small number of instances improperly interpreted and inappropriately escalated to a national estimate. Much of this inaccuracy is presented in the IHS CERA report, *Mismeasuring Methane, Estimating Greenhouse Gas Emissions from Upstream Natural Gas Production*. The analysis points out specific EPA analytical flaws EPA, including:

- The misuse and inaccurate application of Natural Gas STAR program data collected from a small number of wells to assume industry-wide emission rates — based on the

erroneous assumption that methane reported as captured through "green completions" would otherwise be vented to the atmosphere when a green completion is not performed.

- EPA's flawed rounding of data points to the nearest hundredth, thousandth, and even ten thousandth Mcf to overcome the "high variability and uncertainty" in the industry — masking a lack of consistent and reliable data that would undermine the EPA conclusions.
- Developing an assumption that producers in Texas, New Mexico and Oklahoma vent to the atmosphere during flowback, rather than commonly flaring or capturing emissions, simply because those states do not mandate flaring or recovery.

The consequences of overstating emissions in the development of NSPS requirements are threefold. First, overstating emissions leads EPA to conclusions that it needs to address operations based on expectations that the facilities present a major cause for regulatory action. Fully understanding the scope of emissions is essential to making appropriate regulatory targeting judgments. Second, in a NSPS determination, EPA is deciding which of several technologies "reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements)" and whether it has been adequately demonstrated in that application. If the emissions are overestimated EPA will make conclusions that are not well founded. The technology's cost effectiveness will be overstated. Similarly, if the demonstration of the technology's use is based on concentrations of compounds that will be higher than those in reality, it may not function properly. Third, overestimation will assure that the anticipated emissions reductions will never occur.

In the proposed NSPS, the extent of overestimation is extraordinarily high. Following the assessments of EPA's determinations of its emissions basis, companies have reviewed operations and evaluated completion estimates more fully. The results show errors not in percentages but orders of magnitude. One company – that had been active in the Natural Gas STAR program used by EPA for some of its estimations – concluded that EPA's estimates were 14 times the company's actual emissions.

Recommendations

EPA's action on this proposed NSPS has been rushed because of its consent decree with WildEarth Guardians and the San Juan Citizens Alliance. Regulatory actions that can fundamentally influence the ability of independent producers to develop America's natural gas should not be driven by court agreement; they should be driven by science and cost effective technology. Given the vast overestimation of emissions from natural gas well completions and the overly broad scope of the EPA definition of fractured natural gas wells that treats verticals wells and horizontal ones identically, we believe that EPA should not issue these standards. Rather, it should carefully evaluate these emissions and then consider what – if any – additional action is needed.

Storage Vessels

Similar issues arise with regard to the NSPS on storage vessels. The NSPS applies to oil and condensate storage tanks and present both issues associated with the impact on small businesses – particularly with regard to regulations being applied to "modified" tanks and associated with

the underlying data to justify action. Compounding these aspects is EPA's decision to propose a performance based requirement of a 95 percent reduction in emissions.

Scope of Regulation

While the proposal is cast as a NSPS, it would also apply if a facility is considered to be modified. EPA has attempted to simplify the determination of whether a facility is subject to the regulation by using a throughput basis – 20 barrels/day for crude oil and one barrel/day for condensate. While simpler, the throughput approach is not technically sound or supported by the data. However, it can result in substantial exposure consequences for marginal well operators.

Storage tank capacity must be designed to manage production when a production site is initiated. Over time, production from wells decline. As a well field develops, additional wells are piped to common storage tanks in a tank battery. This basic tank battery system remains in place as existing wells decline and are plugged, as new wells are drilled and begin production, and as existing wells are reworked to increase production. An average marginal well in the United States produces about 2 barrels/day. When a well is reworked, its production may increase to 4 or 5 barrels/day for six or eight months before declining back to its prior flow rate. Even though EPA bases its throughput thresholds on an annual average of daily production, clearly, the consequences of normal well field development could result in a storage tank being under the threshold for one year, over the threshold the next year and below again the year after. Under the proposed NSPS, exceeding the threshold would require equipping the tank with a vapor recovery unit (VRU) or flaring system that would no longer be required by the time it was in place.

Such a requirement creates both economic and safety issues. A marginal well producing operation would be hard pressed to economically absorb the costs of a VRU or flare system. If the tank battery receives substantial volumes of produced water, it may have electricity to power a pump to send produced water to a disposal well. If not, new electric service will have to be run to the site. If the site produces only oil, it likely will not have a natural gas pipeline near and an automatic flare must be used.

Oil field stock tanks that contain crude oil, condensate and produced water are typically constructed with a thief hatch at the top of the tank. This hatch is accessed to measure the amount and conditions of the liquid when it is sold. It also serves as a safety device that will relieve the tank of a vacuum to keep the tank from collapsing and that will relieve the tank from pressure increases to keep the tank from bursting. The tank has another safety valve that is usually located in the center of the top of the tank. These safety valves are rarely calibrated because it requires walking on the tank roof, which is considered to be an unsafe practice. From conversations with oil field engineers, it is possibly as high a 30 percent of tanks triggered for emissions control could require replacement. The main reason for the replacement is the potential that the existing tanks would allow oxygen into the vapor recovery process and create an explosive mixture.

The current proposal does not reflect these realities. They are compounded by errors in the estimates of emissions.

Emissions Estimates

Most of EPA's assessment of storage tank emissions comes from a relatively narrow study in Texas. Using this limited base cannot generate the robust information needed to determine whether the VRU or flare control requirements can be adequately demonstrated to provide a 95

percent reduction in emissions. Moreover, EPA compounds the issue by drawing an arbitrary line to define what constitutes crude oil and condensate with the attendant consequence that falling on the wrong side of the line results in a twenty-fold reduction in the throughput that subjects the tank to regulation.

Moreover, EPA's emissions rate for condensate is substantially higher than other estimates. EPA uses a Volatile Organic Compound (VOC) emissions factor of 33.3 lbs/barrel of throughput. Other analyses such as the Colorado Department of Public Health and Environment determined that emissions rates in Colorado are more likely to range from 10.0 to 13.7 lbs/barrel. Consequently, EPA will overstate condensate emissions at any given throughput by a factor of roughly three. As a result, EPA's determination that its NSPS technology will produce a 95 percent reduction must be called into question.

Recommendations

We believe sources should have the ability to estimate VOC emissions from storage tanks rather than be constrained to a throughput based process. If EPA continues to pursue a throughput based approach, it needs to recognize that a more sophisticated approach should be developed. For example, we understand that API is submitting an alternative throughput look-up table for determining exemptions from the storage tank standards in its comments. A critical action that EPA needs to take is addressing the issue of applying its regulations to existing tanks. It needs to develop an approach that does not create an unreasonable burden on existing production, particularly marginal well operations, resulting from short term increases in production. Consequently, we recommend that EPA withdraw the current proposal, develop better emissions assessments and subsequently revisit the technology requirements.

Conclusion

We believe that the current NSPS proposal fails in two key areas for both the REC for fractured natural gas wells and emissions from storage vessels. In each case the emissions assessments are faulty and need substantial improvement. In each case the scope of the proposal threatens smaller producers and marginal well operations due to inadequate analysis of the effects on these components of American natural gas and oil production. Consequently, we believe that EPA should determine not to proceed with these proposals, develop better emissions estimating tools and revisit the determination of an NSPS based on that new information. We are ready to participate in such future efforts. If there are questions or a need for additional information, please contact me at 202-857-4731 or by email at lfuller@ipaa.org.

Sincerely,

Lee O. Fuller
Vice President, Government Relations
IPAA

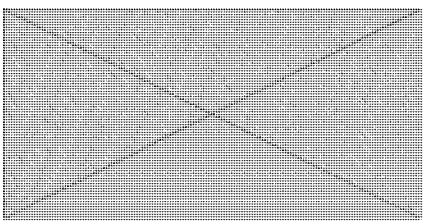
To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: Heather Renschler
Sent: Wed 3/29/2017 8:09:26 PM
Subject: Request for Nominations - Executive Director for Sacramento Metropolitan Air Quality Management District
removed.txt
Brochure - Executive Director APCO.pdf

Sarah,

We are finishing up our outreach for this Executive Director position with Sacramento Metropolitan Air Quality Management District and I wanted to reach out to you to see if you know anyone that might be a good fit for this outstanding opportunity. Attached is a copy of the recruitment brochure for your review and reference. If you know anyone that might be interested let them know that I will be accepting resumes until early next week. Please contact me if you would like to discuss further. I am best reached at this email address or at 916.630.4900. I can also be reached after hours/this weekend on my cell Ex. 6 Thanks

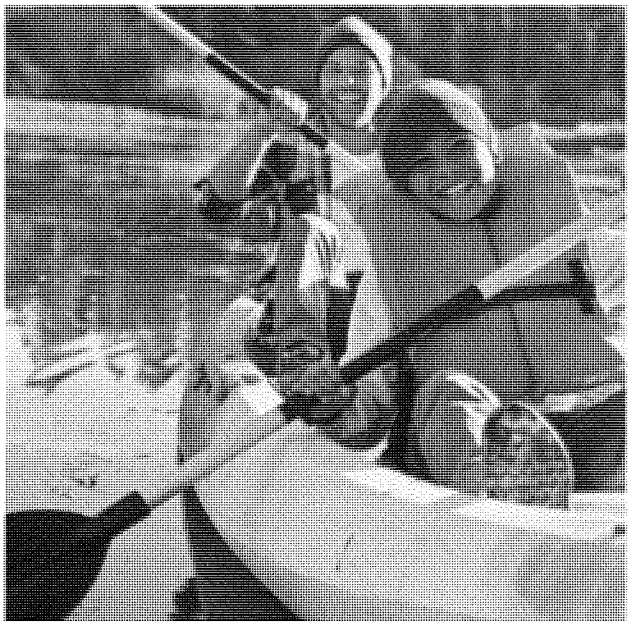
Heather

Heather Renschler
Ralph Andersen & Associates
heather@ralphandersen.com
(916) 630-4900
5800 Stanford Ranch Road, Suite 410
Rocklin, CA 95765
www.ralphandersen.com



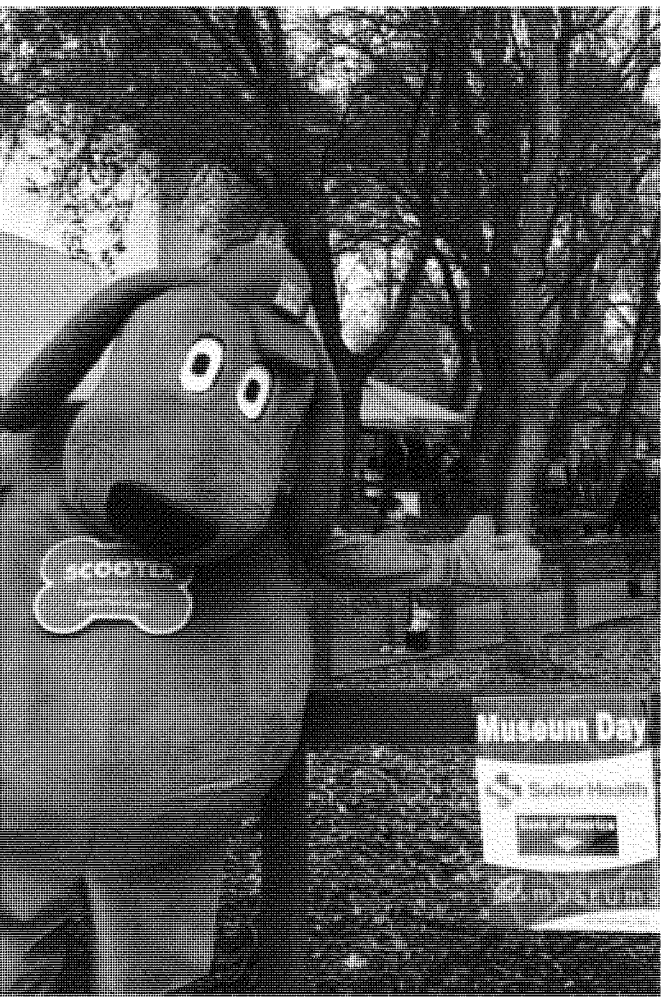
SACRAMENTO METROPOLITAN

AIR QUALITY
MANAGEMENT DISTRICT



EXECUTIVE DIRECTOR / AIR POLLUTION CONTROL OFFICER

Recruitment Services Provided by Ralph Andersen & Associates



A Unique Opportunity

After providing leadership to the organization for more than a dozen years, current Sacramento Metropolitan Air Quality Management District Air Pollution Control Officer & Executive Director, Larry Greene, is retiring. Mr. Greene's retirement creates a unique opportunity to lead one of California's premier Air Quality Management Districts.

The Community

Sacramento's history began in 1839 when John Sutter settled at the confluence of the American and Sacramento Rivers. In 1848, Gold was discovered just 30 miles east of Sacramento. The rest is history. The discovery of gold led to the largest human migration in history. California became a state in 1850 and Sacramento its capital four years later. The area remains one of the fastest growing regions in the country. Sacramento County has a population of 1.5 million, with 491,000 residing within the Sacramento city limits. There are six other incorporated cities, Citrus Heights, Folsom, Rancho Cordova, Elk Grove, Isleton, and Galt. Approximately 583,000 Sacramento County residents live within the unincorporated areas of the county. A significant portion of this area is devoted to rural farms and agriculture.

Many factors contribute to the economic success of the region. A principal reason that Sacramento has retained its attractiveness is that it offers some of the lowest housing prices of major cities in the state. Many new residents have relocated from the San Francisco Bay Area and Southern California to take advantage of Sacramento's employment opportunities, low housing prices, reasonable cost of living, and competitive salaries. The current median home price in the area is just over $300,000.

In addition, the Sacramento region also offers amenities that are attractive to those with an active lifestyle. The Sierra Nevada Mountains, Lake Tahoe, Napa Valley, and the Bay Area are just a short drive from Sacramento and offer an unlimited range of recreational opportunities. Educational opportunities are plentiful, with the Sacramento region being home to California State University, Sacramento; University of California, Davis; Sacramento City College and other community and four-year college programs.

Sacramento is home to the Sacramento Kings NBA basketball team, which plays in the stunning new Golden 1 Center – the first indoor venue in the world to be certified as LEED Platinum, the annual world class Sacramento Music Festival, the Pacific Coast League Sacramento River Cats baseball team, and the Sacramento Republic FC professional soccer team. There are many other recreational, entertainment, and cultural activities in the region including the American River Bike Trail, the Crocker Art Museum, Convention Center, and the California State Railroad Museum. In addition to the many recreational activities locally, the region is adjacent to world class winter skiing in the Sierra Nevada as well as many ocean-related activities along the Pacific Ocean coast of California.

The Position

Reporting to the Board of Directors, the Air Pollution Control Officer, also referred to as the Executive Director, is responsible for carrying out Board policies and directives. These include, but are not limited to:

- Planning, organizing, coordinating, directing, and evaluating District activities;
- Oversight and supervision of permit systems for issuance and renewal of all Authorities to Construct and Permits to Operate to be issued within the District as provided in the California Health and Safety Code;
- Enforcement of all District Rules and Regulations within the District including the collection of fines and approval of mutual settlements;
- Liaison activities between the District and the United States Environmental Protection Agency and the California Air Resources Board relating to the implementation of the District's air pollution control activities;

- Coordinating and conducting federal and state legislative advocacy matters concerning air quality in the District; and
- Managing all District financial, human resources, and labor relations matters.

The Air Pollution Control Officer has five direct reports: Division Managers over Administrative Services Division; Program Coordination; Communications, Land Use and Mobile Sources (COLUMS); and Stationary Sources; along with an Assistant to the Air Pollution Control Officer.

Current Issues and Priorities

Current issues and priorities for the Air Pollution Control Officer will include:

- Federal Standards – Attaining the 1997 and 2008 Federal Ozone Standards, preparing a plan to attain the 2015 Federal Ozone Standard, and maintaining other federal standards applicable to Sacramento.
- Business and Equity Community Relations – Communicating with the business and equity communities in order to continue air quality improvements while being able to maintain a healthy business economy and reduce air quality impacts in low income communities in Sacramento.
- Climate Initiatives – Implementing and supporting federal, state and local climate initiatives in a way that supports continued air quality improvements and gains co-benefits for both programs.
- Fiscal Prudence – Maintaining a fiscally prudent and viable District budget while leveraging funding from outside sources to support District initiatives and programs.
- Succession Planning – Identifying and developing internal staff with the potential to fill key leadership positions in the District.
- Technology Enhancements – Supporting full implementation of several enterprise applications including Financial and Line of Business solutions, to increase the technological capabilities of the District and improve efficiency, accuracy, and customer service.

The Ideal Candidate

The ideal candidate will be an experienced air quality executive, or high-level assistant with significant fiscal and staff management abilities, and an extensive knowledge of air quality issues, regulations, and programs. This energetic and team-oriented leader will bring innovative ideas; effective communication, interpersonal, and public relations skills; and a dedication to improving air quality.

Experience and Education

At least five years of increasingly responsible experience in air quality management. A Bachelor's degree in business, public administration, engineering, environmental science, or related field is expected; a Master's degree is desirable.

Competencies and Personal Characteristics

In addition to the qualities described above, the ideal candidate is:

- An inspiring, visionary leader who can champion the air quality cause;
- An effective and articulate communicator;
- Knowledgeable in federal and California air quality and regulatory issues;
- Knowledgeable in federal and California climate mitigation and adaptation programs and regulations;
- An individual with unquestionable integrity and honesty;
- Politically astute;
- Well-versed in the connection between clean air and public health;
- Sensitive to economic impacts of air quality improvements on area businesses; able to develop mutually beneficial solutions;
- Able to effectively listen to and communicate with equity and low income communities;
- Resourceful; able to deal effectively with key contacts in local, state and federal agencies;
- Persistent; not easily deterred in attaining the District's goals;
- An effective listener; open to listening to differing opinions;

This executive level position requires strong collaboration on a local and regional basis with partner agencies and other local entities.

Additionally, this position has provided strong leadership on a statewide and national basis in both Sacramento and Washington, D.C. The annual "Cap-to-Cap" trip to Washington, D.C. is representative of this type of activity.

- Energetic and proactive;
- A team builder; committedto developing staffto their fullest potential;
- A consensus builder who values collaboration;
- Accessible and responsive to customers/public, the Board and employees;
- Skilled in budgeting and financial management;
- Calm under pressure and possesses a good sense of humor; and
- Creative, bringing new ideas with an openness to those brought by others.

Compensation and Bene f its

The salary for the positionis open and negotiabledepending on the qualifications of the selected candidate. The District offers an attractive benefits package, including:

- **Retirement**– California Public Employees RetirementSystem (PERS) 2%@55 plan for existing PERS members and 2%@62 for new members.
- **Paid Time Off** – Holidays, vacation, sick, and administrative leave annually.
- **Medical, Dental, Vision Insurance** – District provides a health benefitallowance that may be applied to medical, dental, and vision insurance, and other cafeteria plan options.
- **Long-Term Disability Insurance** – District pays 100% of premium for long-term basic coverage.
- **Life Insurance** – District pays 100% of premium for $50,000 coverage on employee.
- **Employee Assistance Program** – District pays 100% of employee coverage premium.
- **AdditionalBenefits** – Auto allowance; monthly expense allowance.

Application Process and Recruitment Schedule

To be considered for the position,please submit a resume with cover letter and current salary to apply@ralphandersen.com. Interested individuals are asked to submit by ***March 31, 2017***. This is a confidential recruitment; references will not be contacted until mutual interest has been established. Confidentiahquiries welcomed to Heather Renschler, Ralph Andersen & Associates at (916) 630-4900.

Resumes will be screened in relation to the criteria outlined in this brochure. Highly qualifiedcandidates with relevant qualifications will be presented to the Search Committee, a five-member sub-set of the Board of Directors, for further evaluation. It is anticipated that preliminary interviews and final interviews are tentatively scheduled to be held in mid-late April and/or early May. A post-offer physical exam is required.

SACRAMENTO METROPOLITAN
AIR QUALITY
MANAGEMENT DISTRICT

The Sacramento Metropolitan Air Quality Management District is an Equal Opportunity Employer.

www.AirQuality.org

The District

The Sacramento Metropolitan Air Quality Management District (District) works cooperatively to coordinate the efforts of local, state and federal government agencies, the business and public health communities, non-profit organizations, and residents to achieve and maintain healthy air quality for Sacramento. This vision recognizes the District alone cannot achieve clean air for Sacramento, but combined with its regulatory role and its lead role in development of innovative programs with community and business involvement, the District can encourage the cooperative inter-agency and public effort necessary to improve air quality.

The District's origins go back to the 1960s when the County of Sacramento Health Department began monitoring air quality. Over the next 20 years, the county expanded air quality programs and the organization evolved to county department status. In 1996, recognizing the regional aspects of air quality improvement, the Sacramento County and Sacramento's incorporated cities established the District as an independent special district.

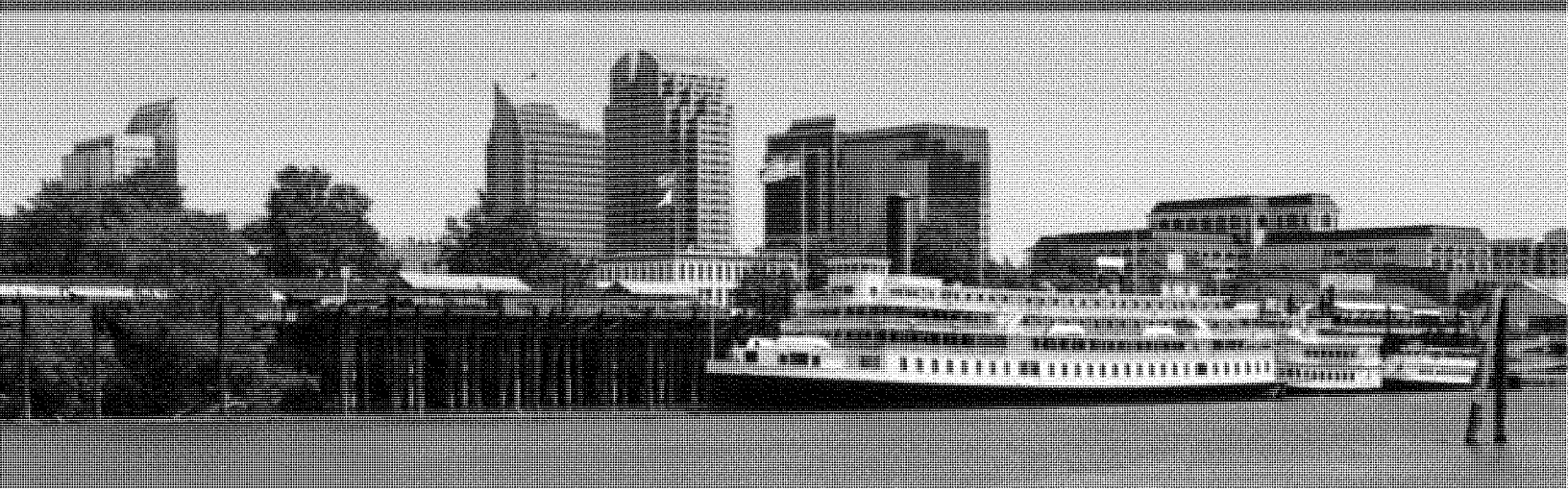
The District's Governing Board is comprised of 14 members, including all five Sacramento County Supervisors, four members of the Sacramento City Council, one member from each of the cities of Citrus Heights, Elk Grove, Folsom, and Rancho Cordova, and one member representing the cities of Galt and Isleton. The Board appoints the Air Pollution Control Officer and the District Counsel. The Air Pollution Control Officer leads the District's work force of nearly 100 employees and is responsible for the District's approved $49.4 million FY2016/17 budget.

The Air Pollution Control Officer and the District Counsel compose the Executive Office of the District. The District is organized into four operating divisions:

- The Administrative Services Division provides fiscal and administrative oversight of District programs including accounting, budgeting, contracts, human resource management, information systems, and property management.
- The Communications, Land Use and Mobile Source Division develops and implements market-based innovative programs to reduce emissions associated with both on- and off-road mobile sources. The Division also implements Transportation Demand Management and Indirect Source Programs, Technology Programs, and Marketing efforts that endeavor to reduce growth-related emissions from land use projects.
- The Stationary Source Division processes permits, determines whether the conditions of those permits have been met, and ensures compliance with District rules and regulations. The Division operates a Permit Inspection that includes Title V and air toxics, and a Field Operations section that covers enforcement, compliance and asbestos related issues, and offers compliance assistance to business sources.
- The Program Coordination Division coordinates the District's planning efforts, including support services critical to those plans, and the development of rules and regulations in consultation with the Stationary Source and Mobile Source Divisions. This Division also performs activities related to emissions inventory, air monitoring, and emission reduction credit bank.

The District provides and emphasizes several innovative, community-based programs to address key issues that affect the air quality in Sacramento. They include:

- Spare The Air – A hallmark program providing residents with resources they can use to protect their health during the summer smog season. The program encourages residents to reduce driving on high ozone days and to be aware of daily ozone levels so that health effects are minimized.
- Check Before You Burn – A key district initiative to set voluntary and mandatory no-burn days for wood burning devices on days when Sacramento County is projected to exceed federal particulate matter 2.5 standards.
- Heavy-Duty Vehicle Incentive Program – An innovative program where the District provides funds from a range of sources to help defray the cost of lower emission technologies for diesel engines.
- Cap and Trade Initiatives – An emerging set of programs implemented by the District and funded through California's Cap and Trade program.



Learn More About The Sacramento Metropolitan Air Quality Management District

Vision

Clean air for all

Mission

Achieve state and federal clean air goals

Core Values

Integrity

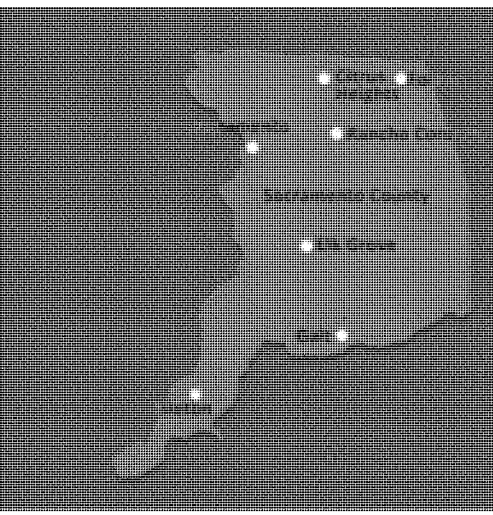
Teamwork

Leadership

Innovation

Strategic Goals

- Maximize program effectiveness while balancing environmental and economic considerations
- Provide regional leadership in protecting public health and the environment
- Integrate air quality consideration into transportation and land use decision-making
- Develop and enhance diverse partnerships
- Recruit , develop, and retain excellent staff
- Influence, develop and implement innovative programs, and promote sustainability throughout the region
- Increase the public's role and responsibility in improving air quality
- Ensure fiscal responsibility and viability



The Governing Board is comprised of members representing the following agencies: Sacramento County and the cities of Citrus Heights, Elk Grove, Folsom, Galt, Isleton, Rancho Cordova, and Sacramento.

Partner Organizations

The District has numerous regional, state, and federal partnerships that assist the District in achieving its mission. Continuing collaborations and leveraging these partnerships are important responsibilities of the Air Pollution Control Officer. A few notable partners are shown below.

To: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: Bill Becker
Sent: Fri 2/17/2017 6:36:45 PM
Subject: NACAA's Recommendations to President Trump on Improving Our Nation's Clean Air Program--We Expect to Transmit Tomorrow
2-16-2017 NACAA Recommendations.pdf
Transmittal.NACAA_Clean_Air_Recommendations-Cover_Letter-FINAL[3].pdf

Sarah--

Here is a document and transmittal letter we just sent to Administrator Pruitt. Would you mind distributing this within OAR, as appropriate. Thanks.

Let me know if you have any questions.

Bill

S. William Becker

Executive Director

National Association of Clean Air Agencies

444 North Capitol St., NW

Washington, DC 20001

www.4cleanair.org

Ex. 6

cell- Ex. 6

Improving Our Nation's Clean Air Program:

Recommendations from the National Association of Clean Air Agencies to President Trump's Administration

February 17, 2017

NACAA

national association of clean air agencies

Introduction

The National Association of Clean Air Agencies (NACAA)[1] is pleased to offer the following recommendations for consideration by Environmental Protection Agency (EPA) Administrator Scott Pruitt and other members of the Administration of President Donald J. Trump related to key issues associated with our nation's clean air program.

The Clean Air Act vests state and local governments with primary responsibility for ensuring that everyone in this nation breathes clean, healthful air. The state and local air pollution control agencies that comprise NACAA's membership are front and center in fulfilling this critically important responsibility. They are uniquely positioned to identify the greatest air quality challenges of the day and to offer advice for confronting those challenges. In short, our recommendations include the following:

1. Improve Technical Assistance to State and Local Agencies
2. Ensure State and Local Air Agencies Have the Resources They Need to Implement Federal Requirements
3. Improve Regulatory Assistance to State and Local Air Agencies Through Effective Federal Measures for Mobile and Stationary Sources
4. Continue and Expand Efforts to Address the Transport of Air Pollution
5. Ensure Effective Establishment and Implementation of the National Ambient Air Quality Standards (NAAQS)
6. Address Critical Air Monitoring Challenges
7. Identify and Address Toxic Air Pollution Challenges
8. Support State and Local Efforts to Address Climate Change
9. Improve the Integration of Federal, State and Local Data Programs and Requirements

We elaborate on each of these issues in the following pages.

NACAA's most important recommendation is that the Trump Administration make working in close collaboration with state and local air pollution control agencies a top priority. We encourage the White House and EPA to forge a truly cooperative partnership with state and local air agencies, which are co-implementers of the Clean Air Act. We invite this Administration not only to reach out to NACAA in the initial stages of any rulemaking and policymaking processes, but also to seek input from and engage NACAA on an ongoing basis. Throughout his campaign, President Trump stated strongly his support for clean air and his desire to ensure it. NACAA urges the Trump Administration to draw on the expertise of state and local air agencies and empower them in every way possible to protect public health and welfare and fulfill their clean air goals.

1 NACAA is a national, non-partisan, non-profit association of air pollution control agencies in 40 states, the District of Columbia, four territories and 116 metropolitan areas. The air quality professionals in our member agencies have vast experience dedicated to improving air quality in the U.S. These recommendations are based upon that experience. The views expressed in these recommendations do not represent the positions of every state and local air pollution control agency in the country. http://www.cleanair.org

1 Improve Technical Assistance to State and Local Air Agencies

Background

Technical assistance from EPA is crucial to the ability of states and localities to carry out their mission to clean up air pollution. EPA's technical support comes in many forms, including educational programs, implementation guidance, and guidance for the performance of complex technical tasks. Over the past decade, however, the agency has dramatically scaled back its support in a number of critical areas.

One area in which EPA's technical assistance is particularly needed is training. Historically, the agency has provided an array of online and classroom courses for state and local agency personnel on a wide variety of air pollution topics – as required under Section 103(a)(5) of the Clean Air Act. State and local agencies relied heavily on this training to familiarize their employees with the intricacies of Clean Air Act requirements that are central to their job functions.

In recent years, funding and staff support for EPA's training functions have declined dramatically and most of the remaining resources have been devoted to newly issued rules. Accordingly, regional air quality planning organizations have had to shoulder much of the burden of developing and coordinating training opportunities for state and local air agencies.

State and local agencies also rely on EPA to provide direction and guidance for the highly technical work they must perform in areas such as air quality modeling. EPA is often slow in providing such guidance and in addressing complex issues that arise with new rules and policies.

A final area where EPA's technical support has been lagging is in the development of emission factors. Emission factors are representative values that estimate the amount of pollutants discharged into the atmosphere by specific processes, fuels, equipment or sources. State and local agencies rely heavily on emission factors in developing emissions inventories and control strategies, determining the applicability of permitting and control programs, and ascertaining and mitigating the pollution effects of individual sources. Unfortunately, over the past decade EPA has only rarely updated existing emission factors, many of which are decades old.

NACAA's Recommendation

The Administration should improve the breadth and timeliness of technical assistance programs that are crucial to state and local air agencies. In particular, EPA should significantly increase the resources it devotes to developing, updating and providing training opportunities in the air pollution control field. The agency should strive to issue technical guidance and support, including the development of new and revised emission factors, in a timelier manner.

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2 Ensure State and Local Air Agencies Have the Resources They Need to Implement Federal Requirements

Background

The Administration has expressed a desire to reset the existing state and federal relationship for implementing the Clean Air Act. In light of that, we urge that such changes include ensuring that state and local agencies have the resources to meet their responsibilities.

Funding for state and local air pollution control programs comes from a variety of sources, including the federal Title V permit fee program, state and local permit and emissions fees and federal grants under Sections 103 and 105 of the Clean Air Act. Section 105 grants support a host of essential activities to attain and maintain healthful air quality. These include ongoing, day-to-day responsibilities that constitute the foundation or "core" of state and local programs. Such activities include efforts to develop and implement State Implementation Plans, monitor emissions, develop emissions inventories, conduct sophisticated modeling of emissions impacts, analyze data, inspect sources of pollution, conduct oversight and enforcement, issue minor source permits, provide technical assistance to regulated sources and respond to citizens' complaints. Section 103 grants have typically funded specific monitoring efforts, such as the fine particulate matter ($PM_{2.5}$) monitoring network.

Clean Air Act Section 105 authorizes federal grants to cover up to 60 percent of the cost of state and local air programs and requires states and localities to contribute a 40-percent match. In reality, however, state and local air agencies provide over 75 percent of their budgets (not including fees collected under the federal Title V program, which can fund only activities related to the Title V permitting), while the federal government provides approximately 25 percent of the total state/local air budget. Although states and localities supply significant resources to their air quality programs, they also rely heavily on the federal grant contribution.

State and local air agencies have done their best to operate with insufficient resources for many years, but it has been a struggle. Recent federal annual appropriations under Sections 103 and 105 of the Clean Air Act have been approximately $228 million – amounts far short of what is needed, especially if there is a shift in responsibilities from EPA to the states. Exacerbating the situation is the fact that federal grants have decreased by nearly 17 percent in purchasing power since 2000 due to inflation. NACAA has calculated that state and local air programs face an annual shortfall of $550 million in federal grants,[2] which has caused many agencies to reduce or eliminate important air pollution programs. This not only harms public health, it can slow down the permitting process for businesses, creating delays and uncertainties.

Recent Administration budget requests have identified specific programs for increased funding (for example, on climate change). Instead, state and local air agencies should be given flexibility on how the funds would be used so that they can target the resources to address the issues that are most pressing in their communities.

A related issue of concern is federal funding for $PM_{2.5}$ monitoring grants. In recent budget requests, the Administration has proposed to begin to shift the $PM_{2.5}$ monitoring grant program from Section 103 authority to Section 105 authority. Unlike funds provided under Section 103, Section 105 grants require states and localities to provide matching funds – something many agencies can ill afford.

Finally, EPA's methodology for allocating Section 105 air grants among the EPA Regions is far out of date. Under refinements to the formula that EPA has proposed to be phased in over five or ten years, some Regions will experience decreased funding. Since Section 105 grants already are inadequate to fund all the programs they

2 *Investing in Clean Air and Public Health: A Needs Survey of State and Local Air Pollution Control Agencies*, NACAA, April 2009, http://www.4cleanair.org/sites/default/files/Documents/Reportneedssurvey042709.pdf

are designed to support, few if any agencies can afford to sufferreductions in their grants. In recognition of this concern, the Senate Appropriations Committee included in its FY 2017 appropriations legislation report language instructions to EPA to ensure that all states and Regions are held harmless (i.e., do not experience a reduction) in fiscalyear 2017. One way to avoid cuts and to address the Senate's concern is for EPA to request, and Congress to appropriate, adequate additional Section 105 grants so that the revised formula can be fully implemented without reductions to any state or local agency's budget.

NACAA's Recommendation

NACAA recognizes that there are many programs that compete for federal assistance and that increases to provide full funding (an additional $550 million) may not be possible. However, the Administration should propose to Congress, and advocate for, increases in federal grants for state and local air agencies. Increases in an amount that would allow EPA to institute the new allocation formula without reducing any state or local agency'sbudget would be a very helpful start toward fillingthe gap. Additionally,EPA should providestate and local air pollution control agencies with the flexibilityto use the additional resources on the highest priority activities in their areas. Finally,grants for $PM_{2.5}$ monitoring should remain under Clean Air Act Section 103 authority, rather than being shifted to Section 105 authority.

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3 Improve Regulatory Assistance to State and Local Air Agencies Through Effective Federal Measures for Mobile and Stationary Sources

Background

While the Clean Air Act requires state and local air pollution control agencies to implement the national air quality program, these agencies rely on EPA to establish strong federal rules to reduce emissions from mobile and industrial sources of air pollution. This work is important for several reasons.

First, the interstate transport of air pollution has a substantial adverse impact on air quality in downwind states, particularly on levels of ozone and fineparticulate matter. Downwind states are usually unable to overcome the impact of these transported emissions without federal action.

Second, many state and local air pollution control agencies are precluded by state or local laws or policies from adopting rules that are more stringent than federal requirements. If the federal rules are not sufficiently vigorous to effectively address air quality problems, those agencies may not be able to meet their air quality goals.

Third, the Clean Air Act generally precludes states, with the exception of California, from establishing standards to address emissions from mobile sources (certain states can, under Section 177 of the Act, opt into motor vehicle standards adopted by California – an important statutory authority that should be preserved). With motor vehicles being dominant contributors to air pollution throughout the country, complying with our statutory obligations to attain and maintain the NAAQS and reduce exposure to hazardous air pollutants, such as diesel particulate matter, requires strong federal standards.

Fortunately, there are opportunities, for additional, meaningful emission reductions from the transportation sector. In particular, for many areas throughout the country, attainment and maintenance of the ozone NAAQS will require additional reductions in nitrogen oxides (NO_x). There is a clear opportunity to garner substantial additional NO_x reductions from heavy-duty vehicles and engines. In June 2016, at least 16 state and local air agencies petitioned EPA to adopt an "ultra-low" NO_x standard of 0.02 grams per brake horsepower hour (g/bhp-hr), down from the current standard of 0.2 g/bhp-hr established in 2000. These improved standards can help states and local agencies achieve their required duty of coming into attainment with existing federal ozone standards. In addition, given the rapid pace at which mobile source greenhouse gas (GHG) emission control technologies are being developed for onroad light-duty and heavy-duty vehicles, there is a great opportunity for further GHG reductions from these vehicles post-model years (MYs) 2025 and 2027, respectively.

NACAA's Recommendation

EPA should assist states and localities in meeting their public-health driven clean air goals by developing in a timely manner appropriately stringent federal rules that address nationally significantstationary and mobile sources, as well as by preserving effective regulations that are already in place.

Specificallywe urge the President to issue specificdirectives and schedules for the timely development and promulgation by EPA of an ultra-low NO_x standard of 0.02 g/bhp-hr and additional phases of GHG emission standards for light-duty vehicles post-MY 2025, and for heavy-duty vehicles post-MY 2027. This work has and can be done in collaboration with the California Air Resources Board and other stakeholders to ensure the standards are sufficiently stringent, as well as practical and achievable.

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4 Continue and Expand Efforts to Address the Transport of Air Pollution

Background

The transport of air pollution across state boundaries from "upwind" sources can impede or even prevent entirely the ability of "downwind" states to attain and maintain the National Ambient Air Quality Standards (NAAQS) for ozone and/or particulate matter (PM). Emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2), both of which are precursors to ozone and PM pollution, and even ozone itself, can travel great distances, affecting air quality and public health hundreds, and even thousands, of miles away.

The problem of interstate transport first rose to prominence in the Eastern and Midwestern United States. In response, EPA adopted regulations to reduce NO_x and SO_2 emissions from electric power plants in those regions of the country; first, the Clean Air Interstate Rule, which was promulgated in 2005 and ultimately vacated by the U.S. Court of Appeals for the D.C. Circuit; and then the Cross-State Air Pollution Rule (CSAPR), promulgated in July 2011. Even with CSAPR and its recent update, transport in the East and Midwest remains a serious problem.

Further, although transport in the Eastern half of the country has dominated the conversation over the past few decades, it is now eminently clear not only that transport is a pervasive and substantial problem in the Western U.S., but also that there are some unique issues associated with it, including that of international transport. Western states are struggling with how to meet their statutory clean air obligations in light of the challenges posed by transport.

NACAA's Recommendation

EPA should continue and expand its efforts related to transport by: (1) developing and promulgating another regulatory update to CSAPR to address the 70-ppb ozone standard; (2) developing a strategy for addressing Eastern and Midwestern transport that ensures region-wide attainment; and (3) working closely with state and local air pollution control agencies to assess transport in the Western U.S. and put in place appropriate programs to address this problem.

ED_001650_00027559-00007

5 Ensure Effective Establishment and Implementation of the National Ambient Air Quality Standards

Background

Under the Clean Air Act, EPA is required every five years to review and, if necessary, revise the National Ambient Air Quality Standards (NAAQS) for six common "criteria" pollutants that are harmful to public health and the environment: ozone, particulate matter, carbon monoxide, lead, sulfur dioxide and nitrogen dioxide. The Clean Air Act makes clear that new or revised NAAQS must be based on the most current scientific evidence without regard to the cost or feasibility of implementation.

Once EPA promulgates a new or revised NAAQS, state and local air pollution control agencies are charged with implementing the standard and are dependent upon EPA to provide timely implementation rules and guidance. Without such tools, state and local air agencies' abilities to meet their statutory deadlines are greatly impeded. Further, because implementation rules and guidance are developed specifically for use by state and local air agencies, it is critical that EPA work closely with these agencies as the materials are drafted.

A key component of state and local air agencies' NAAQS implementation efforts is the development of emission reduction strategies and programs to attain and maintain the standard. These strategies are set forth in State Implementation Plans (SIPs), which must be approved by EPA. The manner in which SIPs are developed and submitted by state and local air agencies and evaluated and processed by EPA has been an issue of considerable concern and discussion for a number of years. In 2010, NACAA, the Environmental Council of the States (ECOS) and EPA established a joint SIP Reform Workgroup to work collaboratively to make the SIP process more efficient and effective while ensuring fulfillment of statutory responsibilities to attain the NAAQS as expeditiously as practicable. A February 2014 agreement, NACAA-ECOS-EPA SIP Reform Workgroup Commitments and Best Practices for Addressing the SIP Backlog, sets forth a total of six commitments and seven best practices, including a commitment by EPA to "clear the SIP backlog (as of October 1, 2013) by no later than the end of 2017, and manage the review of other SIPs consistent with Clean Air Act deadlines."

With respect to implementation of the ozone NAAQS in particular, states across the country, and especially in the West, are confronted with the vexing issue of "background" ozone, which can contribute significantly to monitored ozone concentrations.

NACAA's Recommendation

EPA should: (1) continue the science-based process for reviewing and revising the NAAQS, leaving consideration of cost or feasibility of attainment to the implementation phase; (2) issue timely rules and guidance related to implementation of the NAAQS, developed in close consultation with state and local air agencies; (3) continue to implement the February 2014 NACAA-ECOS-EPA SIP Reform Workgroup Commitments and Best Practices for Addressing the SIP Backlog, including clearing the SIP backlog by the end of 2017; and (4) work with state and local air agencies to better understand the sources and contributions of background ozone.

ED_001650_00027559-00008

6 Address Critical Air Monitoring Challenges

Background

Air monitoring is the backbone of the nation's air pollution control program. The routine, systematic collection of ambient air monitoring data is necessary for determining the extent and location of air pollution problems and for assessing the efficacyof existing emissions control strategies. Monitoring is also used to provide air quality information to the public on a continuous basis, to provide information on air quality trends, to evaluate air quality models, and for research purposes.

The vast majority of the nation's ambient air monitoring networks are operated and maintained by state and local agencies, in accordance with design and operational criteria established by EPA. These monitoring networks comprise hundreds of sites across the country with thousands of monitors measuring ground-level concentrations of criteria pollutants and their precursors, air toxics, meteorological conditions and other parameters. A very significantportion of state and local air program resources is devoted to routine monitoring tasks that must be performed on an ongoing basis by knowledgeable employees.

Unfortunately,state and local agencies are now facing unprecedented challenges in carrying out their critical air monitoring activities. As they struggle to modernize aging monitoring equipment and stave off further deterioration,state and local agencies must also regularly address important new EPA monitoring requirements. For example, over the next several years, many states and localities will contend with expanded ozone monitoring seasons under existing federal requirements.

While they confront major challenges to traditional air monitoring networks, state and local agencies are also contending with rapid developments in small, portable air sensor technologies. Sensor technologies hold a great deal of promise in providing readily available ambient data, not only for individuals, but also for air pollution agencies. On the other hand, many devices are unreliable and the data they produce is not readily comparable to monitoring data measured against the health-based National Ambient Air Quality Standards. State and local agencies are working collaboratively with each other and with EPA to evaluate new sensor technologies, identify goals for their use and to address how to best communicate and educate the public about how to interpret the data they provide.

NACAA's Recommendation

The Administration should address the need for significant federal resources to maintain the nation's ambient air monitoring networks. EPA should continue to work with state and local agencies to prioritize the implementation of any new monitoring requirements to make the best possible use of limited state and local resources. EPA should also expand its efforts to confront the opportunities and challenges associated with rapidly advancing air sensor technologies.

ED_001650_00027559-00009

7 Identify and Address Toxic Air Pollution Challenges

Background

Hazardous air pollutants (HAPs), also referred to "toxic air pollutants" or "air toxics," are substances that are known or suspected to cause cancer or other serious, adverse health effects. The Clean Air Act outlines a multi-pronged process for EPA to address HAP emissions. First, Section 112(b) of the Act identifies 187 HAPs that EPA must regulate. Second, Section 112(c) requires EPA to identify the categories of sources that emit the listed HAPs and to update that list every eight years. Finally, Section 112(d) requires EPA to establish standards to control emissions from the source categories it has identified.

NACAA recently collected information from its members about numerous facilities located throughout the country that emit major amounts of listed HAPs but do not fall under any of the source categories listed by EPA under Section 112(c) of the Act. Methyl bromide fumigation facilities, which are located in multiple locations across the country, are a source of particular concern.

Another issue of concern is HAP emissions from sources that are not large enough to be considered "major" sources, including what are referred to as "non-point," "minor" or "area" sources. These sources are often numerous and widespread, and in some areas, they collectively emit more HAPs than major sources. They tend to be located in highly populated areas, many of which face disproportionate risks from toxic air pollution.

Mobile sources are also significant emitters of HAPs, including diesel particulate matter. State and local air agencies (with the exception of California) are generally precluded from establishing emission standards for mobile sources. Therefore, they are unable to address this significant source of HAP emissions on their own, yet they are expected to reduce the public's exposure to these dangerous substances.

The National Air Toxics Assessment (NATA) is EPA's comprehensive evaluation of HAPs across the United States. NATA includes emissions data as well as modeled estimates of health risks associated with exposures to HAPs. Federal, state and local air quality agencies, as well as the public, use this important tool to help identify the locations and pollutants of greatest concern and to help prioritize programs. Unfortunately, due to the tremendous effort necessary to collect the information and run the models, by the time the NATA results are released they are several years out of date. EPA has recently begun efforts, involving state and local input, to streamline and improve the NATA process.

NACAA's Recommendation

EPA should take the following actions related to hazardous air pollutants: (1) evaluate the completeness of and update as necessary the source category list under Clean Air Act Section 112(c) and, specifically, promulgate a Maximum Achievable Control Technology standard for the methyl bromide fumigation source category; (2) continue and ensure programs address non-major (i.e., non-point, minor or area) and mobile sources of HAPs that can significantly affect local communities); and (3) continue to support NATA and expand on EPA efforts to accelerate the NATA process so that the results can be made available to state and local agencies and the public more quickly.

ED_001650_00027559-00010

8 Support State and Local Efforts to Address Climate Change

Background

Greenhouse gas (GHG) emissions contribute to global climate change. EPA has adopted a number of federal programs to reduce GHG emissions, including regulations to limit GHG emissions from motor vehicles, mandatory GHG reporting requirements and GHG permitting regulations. State and local agencies are required under the Clean Air Act to implement and enforce many of these programs.

Aside from their federal obligations, many states and localities have exercised leadership through local, state and regional action plans and initiatives to address the serious risks that climate change poses to public health and the environment. These efforts have focused largely on emissions from the power sector and involve a wide variety of reduction strategies, including increasing power generation from low- and zero-emitting resources, modernizing the electric grid and reducing electricity demand through improved energy efficiency. Importantly, many GHG reduction approaches offer substantial corollary benefits, including reductions of non-GHG pollutants such as ozone.

States have diverging views over how best to reduce GHG emissions and adapt to climate change. Nonetheless, there has been increased dialogue over the last few years among state and local air agencies, energy regulators, utilities and other stakeholders over how to achieve multiple goals of clean air, cleaner transportation and energy production, grid modernization and GHG emission reductions. NACAA's members are critical parties to these discussions, and federal decisions and requirements may affect their work. The experiences of state and local agencies can serve as guideposts when crafting responses to global climate change.

NACAA's Recommendation

As the Administration considers federal policies related to GHG emissions, we encourage the White House and EPA to consult with state and local air pollution agencies. Further, to the extent that state and local air agencies are obligated to implement and enforce federal GHG-related programs, we request that EPA provide them with the appropriate level of financial and technical resources to meet those responsibilities.

ED_001650_00027559-00011

9 Improve the Integration of Federal, State and Local Data Programs and Requirements

Background

The national air pollution control program relies heavily on electronic data collected by federal, state and local air agencies, including emissions data, facility operational data and many other types of information. These data are vital for assessing air quality and for purposes of compliance assurance, program evaluation, enforcement, regulatory development and other activities. Therefore, it is useful if the data can be shared among the various levels of government. The public must be provided with timely access to air quality data as well.

State and local air agencies have been collecting air quality data for years, and many have expended significant resources to develop sophisticated systems for gathering and analyzing the information. These state and local information collection systems reflect the agencies' own data needs as well as requirements for electronic data submission to the federal government. However, in recent years, EPA has made changes to its compliance and enforcement program's minimum data requirements, some of which may require significantly more data to be submitted than in years past. State and local agencies have traditionally been willing to provide additional data to EPA when requested, but it is not always clear why the data are needed or how they will be used to further the shared goal of improving the environment. Some of this newly required information is too vast for EPA to properly store and process. Moreover, some of EPA's requirements call for the data to be submitted in a format that does not necessarily mesh with or accommodate the needs of existing state and local programs.

Finally, federal efforts to provide the public with access to data on a faster track have led to state and local concerns that information may be made publicly available before federal, state and local agencies have had the opportunity to conduct quality assurance and quality control checks on it. Providing inadequately reviewed, or even flawed data will not serve the public's needs and could undermine the credibility of the air quality program.

NACAA's Recommendation

Federal, state and local data collection programs should be more effectively integrated to address concerns about minimum data requirements, data quality and data use (including public access to data that have not been quality assured). Federal efforts to improve efficiency and streamline data reporting requirements must accommodate existing data collection systems in which state and local agencies have already invested significant resources.

To: Mr Dylan Cors[Ex. 6]
From: Dunham, Sarah
Sent: Thur 9/7/2017 11:23:26 PM
Subject: Fwd: Trump picks Bush-era EPA official for air chief

Sent from my iPhone

Begin forwarded message:

From: "POLITICO Pro Energy Whiteboard" <politicoemail@politicopro.com>
Date: September 7, 2017 at 7:19:44 PM EDT
To: <dunham.sarah@epa.gov>
Subject: Trump picks Bush-era EPA official for air chief
Reply-To: "POLITICO subscriptions" <reply-fe8712797c600c7975-980848_HTML-784727323-1376319-0@politicoemail.com>

By Alex Guillén

09/07/2017 07:16 PM EDT

Pesident Donald Trump has nominated Bill Wehrum, a George W. Bush-era EPA official who since has represented a variety of energy industry interests, to run EPA's powerful air office.

POLITICO reported in July that Wehrum was expected to receive the nod.

As head of EPA's Office of Air and Radiation, Wehrum will play a key role in undoing many of the Obama-era regulations most opposed by Republicans, including the Clean Power Plan, the 2015 ozone standard and forthcoming vehicle emissions rules. Wehrum has been critical of EPA's authority to regulate greenhouse gases, even after the Supreme Court's 2007 ruling saying EPA did have such authority.

He served as a counsel to Jeff Holmstead, Bush's first-term air chief, before replacing Holmstead in an acting capacity from 2005 to 2007. Bush nominated Wehrum to the job permanently, but Democrats blocked his nomination from proceeding in the Senate.

Wehrum spent the past decade as a partner at the Washington, D.C., law firm Hunton & Williams. His clients have included the American Petroleum Industry, American Fuel & Petrochemical Manufacturers, the Utility Air Regulatory Group, the American Chemistry Council, the National Association of Manufacturers and the American Forest & Paper Association.

WHAT'S NEXT: The Senate Environment and Public Works Committee will review Wehrum's nomination in what is certain to be a contentious process.

To view online:
https://www.politicopro.com/energy/whiteboard/2017/09/trump-picks-bush-era-epa-official-for-air-chief-092637

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To: Mccabe, Catherine[McCabe.Catherine@epa.gov]
Cc: Cleland-Hamnett, Wendy[Cleland-Hamnett.Wendy@epa.gov]; Dunham, Sarah[Dunham.Sarah@epa.gov]; Breen, Barry[Breen.Barry@epa.gov]; Stephen J. Caldeira[scaldeira@cspa.org]
From: Phil Klein
Sent: Tue 1/24/2017 9:15:12 PM
Subject: A Letter to President Donald J. Trump from Stephen J. Caldeira of CSPA
President Trump Letter 1.24.2017.pdf

Dear Acting Administrator McCabe,

Attached is a letter to President Trump outlining priority issues for the $100 billion consumer products industry represented by the Consumer Specialty Products Association (CSPA). We believe you have a great number of extremely talented professionals at EPA and provide confidence to the American people from a public health perspective. Our members' products are for the most part in every home and institution in America and that public confidence is vital. CSPA has a good working relationship with US EPA and Steve and I look forward to working with you all and the Trump Administration on these issues.

Phil Klein

Executive Vice President

Legislative & Public Affairs

CSPA®

Consumer Specialty Products Association

1667 K Street NW, Suite 300

Washington, DC 20006

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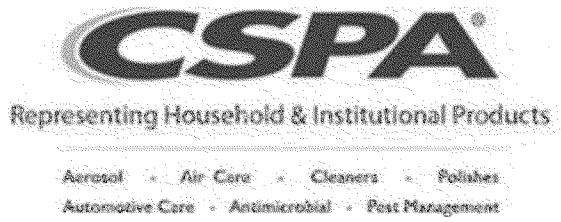
email pklein@cspa.org

web www.cspa.org



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www.cspa.org | p.202-872-8110 f. 202-223-2636

January 24, 2017

The President

The White House

1600 Pennsylvania Avenue, N.W.

Washington, DC 20500

Dear Mr. President:

The 250 member companies of the Consumer Specialty Products Association congratulate you on your successful inauguration and express our steadfast commitment to work with you and your administration to vastly improve the nation's economy.

CSPA is the premier trade association representing the interests of companies engaged in the manufacture, formulation, distribution and sale of more than $100 billion annually in the U.S. of familiar consumer products that help household and institutional customers create cleaner and healthier environments. CSPA member companies employ hundreds of thousands of people globally.

CSPA represents products including disinfectants that kill germs in homes, hospitals and restaurants; air fresheners, room deodorizers, and candles that eliminate odors; pest management products for pets, home, lawn, and garden; cleaning products and polishes for use throughout the home and institutions; products used to protect and improve the performance and appearance of automobiles; aerosol products and a host of other products used every day.

Through our product stewardship program — Product Care® — and the association's retail engagement on chemicals management, transparency and compliance issues, CSPA provides its members a platform for addressing product safety and sustainability.

I have outlined our top priorities for 2017 that involve the U.S. Environmental Protection Agency (EPA). We look forward to working with you, your Administration and the 115th Congress on these issues that are of critical importance to our member companies.

-

Toxic Substances Control Act

The formulated products industry was at the forefront of the successful effort to modernize the law governing the safety of chemicals in commerce – the Toxic Substances Control Act (TSCA). With strong bipartisan support in both chambers of Congress, the law was updated and signed by President Obama in June 2016. The implementation of the new law will be a top priority for our members in 2017.

The new law is intended to enhance consumer confidence and to impose a single, science-based, federal regulatory system, rather than a patchwork of state-by-state laws, which can result in costly and overly burdensome regulations for businesses of all sizes.

Requested Actions:

•□□□□□□ CSPA respectfully requests that you appoint strong leadership for EPA's Office of Chemical Safety and Pollution Prevention. The next EPA Assistant Administrator for the Office of Chemical Safety and Pollution Prevention should be very familiar with the new law and understand the interests of all segments of the regulated community, including consumer product companies. Some of the most important rulemakings under the new law must be promulgated within the first few months of the Trump Administration, and the new Assistant Administrator will need to be in a position to make informed decisions quickly so the chemical industry receives the certainty that all industries and businesses need to create jobs and sustain economic growth.

•□□□□□□ CSPA requests adequate EPA resources for implementation. While the industry funds a portion of EPA's activities under the new law, appropriated funds cover the majority of the costs. Funding for TSCA implementation should increase significantly beyond the baseline set during the years when the law was essentially dormant. Delays on decisions would not only be costly to the chemical industry, but would also stifle job creation.

•□□□□□□ CSPA asks for support from the White House and the EPA Administrator on TSCA. The new EPA Administrator and environmental advisors in the White House should understand that regulation under TSCA is not an impediment to business. In fact, regulation enhances U.S. brands by assuring retailers and consumers that a trusted regulator has evaluated risks from chemicals in a neutral, unbiased, and science-based manner. When science and the new law dictate that restrictions on chemicals are necessary, then EPA should follow through and issue regulations accordingly. Otherwise, some states will step in to fill the gap, creating a patchwork of laws that would be costly and overly burdensome for our member companies to navigate.

EPA's Safer Choice Program

EPA's Safer Choice Program is a ***voluntary program*** with safety and efficacy standards

surrounding ingredients and product packaging. Any product that meets these higher standards is awarded the opportunity to use a program specific logo that can be used on the product label and in advertising, creating a market-based incentive for innovation. The Safer Choice logo helps consumers, businesses, and purchasers find products that are safer for human health and the environment while maintaining a high level of performance. With over 500 industry partners and more than 2,000 products, companies have made significant financial and employee investments to qualify for the Safer Choice logo.

Requested Action:

•□□□□□□ EPA should continue the Safer Choice voluntary program to allow products that meet the standards of the program to carry the logo. Many of our member companies have invested substantial resources to develop and market these products so the potential elimination of the program would negate all of the innovation that resulted from those costly efforts.

•□□□□□□ EPA should expand the program to allow antimicrobial products that meet the standards to carry the logo, unless the products are specifically prohibited from using the Safer Choice logo under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). We have member companies that see the market value (through proactive innovation) of being part of the Safer Choice program.

Reauthorization of the Pesticide Registration Improvement Act

Under FIFRA, a pesticide cannot be used legally if it has not been registered with EPA's Office of Pesticide Programs. The Pesticide Registration Improvement Act of 2003 (PRIA) governs the EPA approval process for pesticides, including a fee schedule for pesticide registration requests. It lists specific timeframes for EPA to make a regulatory decision on pesticide registration and tolerance actions once submitted to the agency. The goal of PRIA was to create a more predictable and effective evaluation process for affected pesticide decisions and couple the collection of individual fees with specific decision review periods. It also promoted shorter decision review periods for reduced-risk applications. PRIA expires on September 30, 2017.

PRIA has been beneficial for stakeholders by providing predictable timelines for industry, new products for consumers, funds for completion of various registration activities (tolerance

reassessment/re-registration), and funds for pesticide safety education for farmworkers.

Reauthorization of PRIA, dubbed PRIA-4, has brought together a coalition that includes CSPA, CropLife America, Responsible Industry for a Sound Environment (RISE), American Chemical Council Biocides Panel, International Sanitary Supply Association (ISSA), Biotechnology Innovation Organization (BIO), Biopesticide Industry Alliance (BPIA), Natural Resources Defense Council (NRDC), Farmworker Justice and the National Association of State Departments of Agriculture. The coalition's proposal is a consensus document that clarifies the intent of the original bill and continues the fee for service program, with some technical adjustments and increased stable funding. Congress should move quickly to reauthorize the highly successful pesticide registration program and provide certainty for the regulated community.

Requested Action:

•□□□□□□ CSPA respectfully requests that you support the legislation that will be introduced shortly and must pass by September 2017.

•□□□□□□ CSPA asks that you sign the bill when it reaches your desk, thereby providing predictability for companies, which will help them to innovate new products, helping grow the economy, and providing important health tools necessary to protect Americans from insect borne disease.

-

Achieve Air Quality Improvements while Maintaining Industry's Ability to Innovate and Expand Economic Growth

Since the late 1980s, CSPA member companies have spent hundreds of millions of dollars to lower volatile organic compounds (VOCs) in consumer products to help improve air quality while maintaining our industry's ability to supply effective and affordable products that consumers can rely on to benefit their health, safety and quality of life each and every day.

Specifically, CSPA worked cooperatively with EPA in developing the current national consumer

products regulation. Moreover, because many consumer products are manufactured for a nationwide or regional marketplace, CSPA has worked cooperatively with the California Air Resources Board to support technologically and commercially feasible regulations that California needed to comply with the federal ozone standards. CSPA is on record supporting regionally consistent regulations in 16 other states to improve air quality without imposing unnecessary impediments to interstate commerce.

However, CSPA member companies have serious concerns about the feasibility of achieving the recently promulgated 2015 national ambient air quality standards (NAAQS) for ozone within the current timeframe established by EPA. In addition, we are very concerned about the cost burdens that the scheduled implementation of the ozone standards will impose on our country:

- Short-term: restricts businesses from expanding existing facilities or building new facilities in areas of the country that fail to comply with the 2015 ozone standards.

- Long-term: requires states to implement updated regulatory requirements that will force companies to expend significant amounts of money to reformulate their products.

During the 114th Congress, CSPA joined with other industry groups supporting commonsense legislation to: (1) provide states with more time and flexibility to implement the 2015 ozone standards by extending regulatory deadlines; (2) reform the regulatory review period for NAAQS; and (3) improve the regulatory process to include consideration of feasibility, cost and additional information.

Requested Action:

- It is anticipated that similar legislation will be introduced and passed by the 115th Congress. Once Congress acts to pass this necessary legislation, we would respectfully urge you to sign the bill(s) and enact laws to achieve improvements in air quality while allowing companies to innovate and help the economy grow.

<u>Resource Conservation and Recovery Act</u>

The Resource Conservation and Recovery Act (RCRA) provides the national framework for the solid waste program established by Congress and gives EPA the authority to develop the program, regulations, policy, and guidance for the handling of hazardous and non-hazardous solid waste. While non-hazardous solid waste is regulated under the statute, states play an important role in the implementation and may enact more rigorous standards. Hazardous waste, regulated under another section of the statute, is treated differently—it is regulated by the states and if a state fails to have a program, EPA implements the requirements for the state.

EPA recently released the Hazardous Waste Generator Improvements Rule, which contains suggested changes in RCRA regulations and RCRA policy and guidance. EPA has stated its intention to develop a proposed rule that would address aerosol cans as universal waste and, therefore, they would not need to be classified as hazardous waste.

Requested Action:

• CSPA urges EPA to promptly draft and publish for comment the proposed regulation indicating that aerosol containers be classified as universal waste. CSPA member companies support this action, which would increase the recycling of aerosol containers.

Thank you for your consideration of CSPA member companies' most important public policy issues. We would be truly grateful for the opportunity to brief White House and EPA staff on our positions.

Most respectfully,

Stephen J. Caldeira

President & CEO

cc: Catherine McCabe, Acting Administrator, U.S. Environmental Protection Agency

CSPA®
Representing Household & Institutional Products
Aerosol - Air Care - Cleaners - Polishes
Automotive Care - Antimicrobial - Pest Management

January 24, 2017

The President
The White House
1600 Pennsylvania Avenue, N.W.
Washington, DC 20500

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- EPA should continue the Safer Choice voluntary program to allow products that meet the standards of the program to carry the logo. Many of our member companies have invested substantial resources to develop and market these products so the potential elimination of the program would negate all of the innovation that resulted from those costly efforts.

- EPA should expand the program to allow antimicrobial products that meet the standards to carry the logo, unless the products are specifically prohibited from using the Safer Choice logo under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). We have member companies that see the market value (through proactive innovation) of being part of the Safer Choice program.

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Reauthorization of PRIA, dubbed PRIA-4, has brought together a coalition that includes CSPA, CropLife America, Responsible Industry for a Sound Environment (RISE), American Chemical Council Biocides Panel, International Sanitary Supply Association (ISSA), Biotechnology Innovation Organization (BIO), Biopesticide Industry Alliance (BPIA), Natural Resources Defense Council (NRDC), Farmworker Justice and the National Association of State Departments of Agriculture. The coalition's proposal is a consensus document that clarifies the intent of the original bill and continues the fee for service program, with some technical adjustments and increased stable funding. Congress should move quickly to reauthorize the highly successful pesticide registration program and provide certainty for the regulated community.

Requested Action:

- CSPA respectfully requests that you support the legislation that will be introduced shortly and must pass by September 2017.

- CSPA asks that you sign the bill when it reaches your desk, thereby providing predictability for companies, which will help them to innovate new products, helping grow the economy, and providing important health tools necessary to protect Americans from insect borne disease.

Achieve Air Quality Improvements while Maintaining Industry's Ability to Innovate and Expand Economic Growth

Since the late 1980s, CSPA member companies have spent hundreds of millions of dollars to lower volatile organic compounds (VOCs) in consumer products to help improve air quality while maintaining our industry's ability to supply effective and affordable products that consumers can rely on to benefit their health, safety and quality of life each and every day.

Specifically, CSPA worked cooperatively with EPA in developing the current national consumer products regulation. Moreover, because many consumer products are manufactured for a nationwide or regional marketplace, CSPA has worked cooperatively with the California Air Resources Board to support technologically and commercially feasible regulations that California needed to comply with the federal ozone standards. CSPA is on record supporting regionally consistent regulations in 16 other states to improve air quality without imposing unnecessary impediments to interstate commerce.

However, CSPA member companies have serious concerns about the feasibility of achieving the recently promulgated 2015 national ambient air quality standards (NAAQS) for ozone within the current timeframe established by EPA. In addition, we are very concerned about the cost burdens that the scheduled implementation of the ozone standards will impose on our country:

- Short-term: restricts businesses from expanding existing facilities or building new facilities in areas of the country that fail to comply with the 2015 ozone standards.
- Long-term: requires states to implement updated regulatory requirements that will force companies to expend significant amounts of money to reformulate their products.

During the 114th Congress, CSPA joined with other industry groups supporting commonsense legislation to: (1) provide states with more time and flexibility to implement the 2015 ozone standards by extending regulatory deadlines; (2) reform the regulatory review period for NAAQS; and (3) improve the regulatory process to include consideration of feasibility, cost and additional information.

Requested Action:

- It is anticipated that similar legislation will be introduced and passed by the 115th Congress. Once Congress acts to pass this necessary legislation, we would respectfully urge you to sign

the bill(s) and enact laws to achieve improvements in air quality while allowing companies to innovate and help the economy grow.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) provides the national framework for the solid waste program established by Congress and gives EPA the authority to develop the program, regulations, policy, and guidance for the handling of hazardous and non-hazardous solid waste. While non-hazardous solid waste is regulated under the statute, states play an important role in the implementation and may enact more rigorous standards. Hazardous waste, regulated under another section of the statute, is treated differently—it is regulated by the states and if a state fails to have a program, EPA implements the requirements for the state.

EPA recently released the Hazardous Waste Generator Improvements Rule, which contains suggested changes in RCRA regulations and RCRA policy and guidance. EPA has stated its intention to develop a proposed rule that would address aerosol cans as universal waste and, therefore, they would not need to be classified as hazardous waste.

Requested Action:

- CSPA urges EPA to promptly draft and publish for comment the proposed regulation indicating that aerosol containers be classified as universal waste. CSPA member companies support this action, which would increase the recycling of aerosol containers.

Thank you for your consideration of CSPA member companies' most important public policy issues. We would be truly grateful for the opportunity to brief White House and EPA staff on our positions.

Most respectfully,

Stephen J. Caldeira
President & CEO

cc: Catherine McCabe, Acting Administrator, U.S. Environmental Protection Agency

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Agenda:

1. Schedule
2. CMAQ vs CAMx (tentative)
3. 2020 (2023?) Platform Development Plans

a. Schedule
b. Inventory Approach

4. NODA Comments – 2/28 at 9:30
5. Monitoring

c. PAMS EMP
d. Ozone Monitoring QA Issue

6. Base Year Interregional Workgroup
7. Paper – Jaffe et al
8. Other Topics

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Meteorological anomalies lead to elevated O_3 in the western US in June 2015

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Key Points:

- Surface O_3 was significantly enhanced in the Western U.S. in June of 2015 due to multiple meteorological anomalies.
- The elevated ozone caused several urban air quality sites to have many days with maximum 8-hour averages over 70 ppb.
- The data in June 2015 show enhanced ozone/temperature slopes at several sites, compared to previous June data.

Abstract

In winter through early summer of 2014–2015, temperatures in the western U.S. were substantially enhanced due to a persistent high pressure ridge and warm water in the northeastern Pacific Ocean. Concurrently, monthly averaged maximum daily 8-hour average (MDA8) O_3 in June 2015 was enhanced by 3–13 ppb across a large portion of the western U.S. At the Mt. Bachelor Observatory (2.8 km asl) in central Oregon, O_3 in June 2015 was enhanced by 11 ppbv compared to the long-term mean. Some urban areas had many days in June 2015 with MDA8 values above the current air quality threshold of 70 ppbv. We show that the high O_3 was associated with enhanced temperatures, reduced cloud fraction, increased stagnation, and increased biogenic emissions. The data in June 2015 show enhanced $\Delta O_3/\Delta$temperature slopes at several sites, compared to previous June data, due to these multiple factors.

1 Introduction

Ozone (O_3) is an important air pollutant that increases respiratory stress and is associated with a number of health issues, up to and including premature mortality [*Bell et al.*, 2004; *Lippmann*, 1993; *Silva et al.*, 2013]. In the lower atmosphere, O_3 is photochemically generated by reactions involving nitrogen oxides and hydrocarbons, which are emitted by industrial processes, combustion, and natural sources. In the U.S. nearly all regions have substantially reduced anthropogenic emissions of the precursors over the past several decades, and, thus, peak O_3 concentrations have declined considerably in most areas [*Cooper et al.*, 2012; *Simon et al.*, 2015; *Strode et al.*, 2015]. At the same time, the U.S. Environmental Protection Agency (EPA) has tightened the O_3 standard several times in response to new health data. The most recent change to the standard came in 2015, when the allowable maximum daily 8-hour average (MDA8) was reduced to 70 ppb [*National Ambient Air Quality Standards for Ozone*, 2015]. The form of the standard is complex, with an area

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being considered in attainment of the standard if the 3-year average of the annual 4th highest MDA8 is 70 ppb or below.

Meeting the new O_3 standard will present a significant challenge for many regions of the country. One reason is that U.S. background O_3 (USB) is already a substantial fraction of the 70 ppb standard. USB is defined as O_3 formed from natural sources in the U.S. plus natural and anthropogenic sources in countries outside the U.S. [*Dolwick et al.*, 2015]. Essentially, USB quantifies the natural and foreign sources of O_3 that would be difficult or impossible to control. USB varies daily and is a function of season, meteorology, and elevation. O_3 increases as a function of altitude, so higher elevation sites are exposed to higher concentrations of O_3. For this reason, many parts of the western U.S. have seasonal average USB concentrations that are up to 70% of the 70 ppb standard [*Zhang et al.*, 2011]. Studies have indicated that daily variations in USB are an important control on urban air quality in the western U.S. [*Langford et al.*, 2015; *Parrish et al.*, 2010; *Wigder et al.*, 2013]. At the same time, USB appears to be increasing in the western U.S. [*Cooper et al.*, 2010; *Gratz et al.*, 2015].

Increasing temperatures, due to climate change, will also present a challenge for meeting the new O_3 standard. This is because O_3 production increases with temperature [*Sillman and Samson*, 1995] and because temperature co-varies with other factors that are conducive to O_3 production and accumulation (e.g., emissions, stagnation, solar insolation). Thus, most analyses of air quality in urban areas find that temperature is one of the most important variables to explain variations in daily O_3 concentrations [*Camalier et al.*, 2007]. Many studies have attempted to predict future O_3 and health impacts in the U.S. based on estimates of future emissions, meteorology, and USB (e.g., [*Bell et al.*, 2007; *Chen et al.*, 2009; *Avise et al.*, 2012; *Fang et al.*, 2013; *Fann et al.*, 2015; *Pfister et al.*, 2014; *Rieder et al.*, 2015; *Weaver et al.*, 2009]. A wide range of results have been reported, depending on the assumptions made. For example, *Chen et al.* [2009] projected an annual average increase in MDA8 O_3 of 9.6 ppb in 2050, averaged across the U.S., due largely to increases in USB using the IPCC A2 emission scenario. *Pfister et al.* [2014] also projected a significant increase in U.S. surface O_3 in summer, based on future temperatures and the A2 Representative Concentration Pathway (RCP) 8.5 emission scenario. In contrast, *Wu et al.* [2008] used IPCC emission scenario A1B and projected significant reductions in summertime MDA8 O_3 across the U.S., but this projected reduction is partially offset by climate change. *Steiner et al.* [2010] suggested that changes in the relationship between temperature and O_3 at very high temperatures may moderate future changes in O_3 due to climate change. *Weaver et al.* [2009] compared results from 12 global and regional scale models used to project future O_3 in the U.S. and found significant differences between models. Thus, model projections of future O_3 are highly uncertain and depend critically on the assumptions made with respect to U.S. and global emissions and future meteorological conditions.

While global average temperature continues to increase, this trend is not spatially or temporally uniform. Starting in late 2013, a transition from the negative to positive phase of the Pacific decadal oscillation brought with it exceptionally warm sea surface temperatures (SSTs) in the North Pacific [*Blunden and Arndt*, 2016; *Bond et al.*, 2015; *Hartmann*, 2015; *Mote et al.*, 2016]. These conditions persisted through 2014 and into 2015. In the North Pacific, the SST anomaly was 2.5 standard deviations above the long-term mean for most of 2015 [*Blunden and Arndt*, 2016]. The warm waters in the North Pacific had significant ecological impacts on marine mammals and caused extensive growth of harmful algae on the entire west coast of the U.S. in the summer of 2015 [*Blunden and Arndt*, 2016; *Cavole et al.*, 2016; *McCabe et al.*, 2016]. The anomalous SSTs also impacted air temperatures across the western U.S. [*Bond et al.*, 2015]. *Mote et al.* [2016] argue that the 2014–2015 temperature

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anomaly was, in part, due to anthropogenic influence on climate change. While the anomalously high temperatures and O_3 were both present for much of 2014 and the first half of 2015, our analysis focuses on June, when USB concentrations are already high [*Gratz et al.*, 2015]. For June 2015, the monthly mean temperatures across the western U.S. were enhanced by 1–6°C over the long-term mean and monthly average MDA8 O_3 values were enhanced up to 11 ppb. During this period, many individual air monitoring stations had numerous days with MDA8 values greater than 70 ppb. Our analysis focuses on the role of temperature, cloud cover, stagnation, and biogenic emissions in explaining the high O_3 days. Based on our analysis, we conclude that O_3 was not enhanced due to an increase in USB, but was associated with enhanced O_3 production from domestic emissions, combined with exceptional meteorological conditions. We also examine the slope of the O_3-temperature relationship for this unusually warm period.

2 Methods

The Mt. Bachelor Observatory (MBO) is a mountain-top observatory at 2.8 km above sea level operated by the University of Washington since 2004 [*Jaffe et al.*, 2005]. Ozone and other chemical tracers are measured using standard UV methods and calibrations are referenced to a Washington State transfer standard, which is calibrated against the EPA Region 9 Standard Reference Photometer. At the MBO a diurnal cycle in O_3, water vapor, and other tracers indicates a clear diurnal pattern in free tropospheric (FT) air vs boundary layer (BL) influence at the site. We have used water vapor mixing ratios as a means to separate FT air at the site [*Ambrose et al.*, 2011]. By comparing the MBO data to radiosonde data from two nearby sites, we identify a monthly water vapor criteria. Water vapor mixing ratios below this value correspond to the FT data (Table S1). Details on O_3 and other measurements at the MBO are in previously published papers [*Ambrose et al.*, 2011; *Gratz et al.*, 2015]. O_3 and meteorological data from other locations are taken from the EPA Air Quality System (AQS) database (https://www.epa.gov/air-data).

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Satellite-derived cloud fraction are from the Atmospheric Infra-Red Sounder onboard NASA's Aqua satellite. Data are accessed at http://giovanni.gsfc.nasa.gov/giovanni/. For large-scale meteorological analyses, we use results from the National Center for Environmental Prediction's North American Regional Reanalysis (NCEP-NARR). This is a combined high-resolution model/data assimilation analysis of meteorological patterns covering 1979–present. We access the results via the NOAA Earth System Research Laboratory (http://www.esrl.noaa.gov/psd/data/gridded/data.narr.html). Vertical profiles of winds were obtained from twice daily radiosonde observations at 0 and 12 Greenwich Mean Time. Data were accessed via the University of Wyoming atmospheric data site (http://weather.uwyo.edu/upperair/sounding.html). Backward air mass trajectories were calculated using the NOAA-HYSPLIT model (http://ready.arl.noaa.gov/HYSPLIT.php) with the GDAS $1^{\circ} \times 1^{\circ}$ meteorological dataset [*Stein et al.*, 2015]. We used a trajectory starting height of 500 meters above ground level (AGL) for each site, except for MBO, where a starting height of 1500 meters AGL was used. This reflects the fact that model terrain in mountainous regions does not reflect true topography. We have previously shown that 1500 meters AGL is the best height to use for MBO with the 1°x1° GDAS dataset [*Gratz et al.*, 2015]. The formaldehyde column data at a $0.25^{\circ} \times 0.25^{\circ}$ grid resolution was derived from OMI/AURA observations using differential optical absorption spectroscopy (DOAS) technique combined with radiative transfer calculations. We access the database via Royal Belgian Institute for Space Aeronomy (http://h2co.aeronomie.be). For all spatial plots shown in this manuscript, we used Kriging methods to interpolate the data.

3 Results and Discussion

Figure 1a shows the June monthly mean O_3 ($\pm 1\sigma$) at the MBO for 2004–2015. The June 2015 mean was 56.0 ppb, 12 ppb greater than the average of the previous 11 years. A t-test demonstrates that the difference between the 2004–2014 mean and 2015 is highly significant ($P < 0.001$). The anomalous O_3 at the MBO was seen in both free tropospheric air and boundary layer influenced air (Figure S1). In addition, other tracers, such as carbon monoxide and water vapor, were not significantly changed in 2015 (Figure S2). This indicates that neither enhanced long-range transport of pollution [*Jaffe et al.*, 2004] nor upper troposphere/lower stratospheric air mass intrusion could explain the enhanced O_3 in 2015. Figure 1b shows the June 2015 monthly averaged MDA8 from all EPA sites in the continental U.S. This shows the highest MDA8 values in Southern California extending to the Rocky Mountain region and the Pacific Northwest. Figure 1c shows the anomaly in monthly averaged MDA8 compared to previous June data (2010–2014). Because peak O_3 concentrations are declining in most urban areas of the U.S. [*Simon et al.*, 2015], we chose to compare the 2015 data with the most recent 5 years, rather than a longer time period. Here the data show that the highest anomalies in MDA8 extend from central California and across most of the western U.S. In a number of urban areas there were many days in June 2015 with MDA8 values greater than 70 ppb. For example, Salt Lake City, UT, had 16 days in June 2015 alone with MDA8 values above 70 ppb, whereas in the previous 5 years, they averaged only 2 days per month in June with values over 70 ppb.

Figure 2a shows the anomalous pattern of temperature in June 2015 at 850 mbar (approximately 1.5 km asl). The monthly mean temperature anomaly was more than 5°C in some regions. The pattern at the surface is nearly identical. The region with a temperature anomaly of more than 2°C extended from approximately San Francisco, CA, to the Canadian border and from central Wyoming and Utah westward to the Pacific Coast. The temperature anomaly over North America is clearly linked to the warm SSTs over the North Pacific [*Bond et al.*, 2015], but it is also linked with other factors including a high pressure ridge, reduced

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winds, and decreased cloud cover, as described below. Figures S3a and S3b show the climatological June mean and June 2015 anomaly for the 850 mbar geopotential height. The figures show that the mean position of the Pacific high in June 2015 has shifted to the northeast, the Aleutian low pressure system has receded to the north and the zone of low pressure is much weaker than usual. One important effect of this change was to shift the region of strong zonal flow to the north. Figure 2b shows the 850 mbar zonal wind anomaly for June 2015. What is usually a strong zonal or westerly wind flow into the northern United States has been reduced considerably in June 2015.

A reduction in mean wind speeds in the northwestern U.S. was confirmed using two approaches. First, we examined vertical wind data from 8 routine radiosonde sites in the northwest region that were most impacted by the change in zonal flow. The data (shown in Table S2) show that wind speeds at 0–4 km above sea level in June 2015 are, on average, 18% lower than in the previous 10 years. Second, we examined backward trajectories from the HYSPLIT model calculated for 9 sites in the region. Table S3 shows these results. The trajectories also confirmed reduced air mass transport (e.g., lower average wind speeds) in June 2015. On average, the 24-hour transport distances in June 2015 were reduced by 27% across all sites compared to the previous 7 years. The combination of reduced wind speeds and reduced trajectory transport distances indicate greater stagnation and accumulation of pollutants in June 2015 compared to previous years.

The enhanced temperature resulted in another important factor: reduced cloud cover. Figure 2c shows that the mean relative humidity (RH) (%) for June 2015 at 850 mbar was reduced by more than 15% across the northwest region. At the MBO, average RH was reduced by 19.7% in June 2015, compared to the previous 10 years. This reduced RH resulted in much lower cloud cover, as seen by the AIRS instrument on the NASA Aqua satellite (Figure 2d). For the Pacific Northwest region, bounded by 124–112°W and 40–48°N (box in Figure 2d), the average daytime cloud fraction in June 2015 was 0.31, compared to 0.41 in the 12 previous years. The reduction in cloud cover likely increased photochemical production of O_3 from regional sources.

We also considered two other factors that might have influenced O_3 during this time: boundary layer heights (BLH) and increased biogenic emissions in the region. Both might increase during periods of warmer temperatures. For BLH, we examined results from the Weather Research and Forecasting (WRF) model, run at the University of Washington, which simulates meteorology at a resolution of 4 km. The results for June 2015 showed no consistent pattern across the model domain compared to earlier years (see Table S4). This is consistent with the results reported by *Jacob and Winner* [2009], who find no clear relationship with BLH and surface O_3.

If O_3 production is limited by volatile organic compounds (VOCs), then changes in biogenic emissions could also contribute to enhanced O_3. *Steiner et al.* [2006] used the CMAQ model and demonstrated significant O_3 sensitivity to biogenic VOCs for central California. In the Pacific Northwest, O_3 sensitivity to VOCs is usually observed during peak O_3 periods [*Xie et al.*, 2011]. Given the strong positive temperature dependence of these emissions [*Guenther et al.*, 2012], it is possible that changes in biogenic VOCs contributed to the enhanced O_3 seen in June 2015. The enhancement in biogenic VOC emissions can be approximated by the relationships described in *Guenther et al.* [2012]. For a 4°C enhancement in temperature (see Figure 2), we would expect an increase in isoprene, sesquiterpenes, and monoterpenes of 60, 97, and 49%, respectively. To examine possible changes in biogenic emissions in 2015, we used satellite-derived formaldehyde, since this is

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indicative of isoprene, as well as α and β-pinene emissions, which are also abundant in the western U.S. [*Guenther et al.*, 2000; *Palmer et al.*, 2006]. Figure S4a shows the mean formaldehyde column for June 2010–2014, and Figure S4b shows the June 2015 anomaly as a % of the earlier years. While we see some evidence for enhanced formaldehyde, we note that the formaldehyde columns over the western U.S. are very low. Over the region bounded by 124–112°W and 40–48°N, column formaldehyde in June 2015 is enhanced by 39%, relative to the previous 5 years. However, caution should be used in interpreting this value as the cloud fraction in 2015 was also significantly reduced. To our knowledge, there are no other isoprene, terpene, or formaldehyde data for the region for this time period. In summary, biogenic VOCs are likely important as O_3 precursors in the western U.S., and we see some evidence for enhanced biogenic emissions based on the OMI formaldehyde columns in June 2015.

The results above suggest that the enhanced O_3 seen in June 2015 was likely due to enhanced local and/or regional photochemical production, rather than enhanced transport of anthropogenic precursors from regional, global or background sources. This is confirmed by examining tracers of pollution and upper troposphere/lower stratospheric (UTLS) sources of O_3, as measured at the MBO. Based on past analysis of MBO data [*Ambrose et al.*, 2011], carbon monoxide (CO), aerosols, and water vapor mixing ratios are good tracers for global pollution or UTLS sources. For June 2015, the average CO, aerosol scattering coefficient, and water vapor mixing ratios were 111.4 ppb, 7.4 Mm^{-1}, and 4.5 g/kg, compared to long-term means for June of 110.5 ppb, 4.2 Mm^{-1}, and 4.4 g/kg. So while the average June 2015 temperature at the MBO was enhanced by 5.4°C and the % relative humidity decreased by 19.7%, the CO and water vapor mixing ratios were essentially identical to their long-term means. Aerosols are likely enhanced due to the lower frequency of clouds observed in 2015. At the MBO, we saw no evidence for enhanced pollution (e.g., enhanced CO or aerosols) or UTLS (decreased water vapor mixing ratio) in June 2015 (Figure S2). We also evaluated water vapor mixing ratios using the same 8 radiosonde sites, as described earlier. For 0–4 km above ground level, the June 2015 water vapor mixing ratios were slightly greater (6.8%) compared to the long-term mean. These data are shown in Table S5. Thus, both the MBO data and radiosonde data from 8 sites in the Western U.S. indicate that the enhanced O_3 in June 2015 was likely of domestic origin and not due to global background sources, such as long-range transport of pollutants or UTLS intrusions.

Figure 3 shows the relationship between MDA8 O_3 and the daily maximum temperature for four representative sites in the western U.S. for June data in 2010–2015, with data for 2015 shown in red. We use data from only the past 5 years to minimize effects from changing emissions. While all of the data demonstrate a relationship between MDA8 O_3 and the daily maximum temperature, the relationship in 2015 is rather different. The 2015 data show the enhanced temperatures; however, O_3 values are also higher at the same temperature compared to previous years. The $\Delta O_3/\Delta$temperature linear regression slopes are greater in 2015 for all sites. The difference is statistically significant for two of the four sites ($P<.05$, Sacramento and Seattle) (, see Table S6). At 35°C the O_3-temperature relationships suggest an additional 4–18 ppb of O_3 at these 4 sites.

Our conclusions differ somewhat from those reported by *Steiner et al.* [2010], who suggested that climate change impacts on O_3 may be ameliorated by a reduced $\Delta O_3/\Delta$temperature slope at the highest temperatures (daily maximum temperature greater than 39°C). For the sites considered in Figure 3, only Sacramento shows any days with daily maximum temperatures at this level or above. Despite the fact that the average daily maximum temperature in Sacramento in June 2015 was 3.1°C higher, compared to previous years, there were only 4 days with a maximum temperature of 39°C or greater. So while the

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results of *Steiner et al.* [2010] show a reduction in the $\Delta O_3/\Delta$temperature slope above 39°C, we see few days with such a high daily maximum temperature and no reduction in the slope in June 2015. Likely the 2015 data show the combined effects of temperature, winds, and solar insolation, and so any small reductions in O_3, due to high temperatures, are offset by the impact of reduced wind speeds and solar insolation. The data in Figure 3 indicate that temperature alone did not cause the enhanced O_3, but that reduced wind speeds and cloud cover, plus possibly enhanced biogenic emissions, also contributed.

5 Conclusions

Surface O_3 in the U.S. may increase or decrease in the future. Continued emissions reductions in the U.S. will tend to reduce concentrations, but these may be offset by rising temperatures and/or increasing international emissions. In addition, understanding the inter-annual variations in O_3 is important to fully comprehend the implications of the 3-year average in compliance metrics (i.e., the 3-year average of the fourth highest MDA8), since a single high year can put a region out of compliance with the standard. We have shown how changes in temperature, wind speeds, and cloud cover combined to cause an unusually high O_3 year in the western U.S. During June 2015 alone, some urban sites in the western U.S. had as many as 16 days above the 70 ppb threshold. Our analysis indicates that this enhanced O_3 in June 2015 was due to O_3 production from domestic sources caused by the anomalous meteorological conditions. Understanding how much of the O_3 change was due to each factor individually will require detailed atmospheric modeling. At the same time, a comparison of chemical models with the 2015 O_3 season would help improve our predictions of future changes in O_3.

Acknowledgments, Samples, and Data

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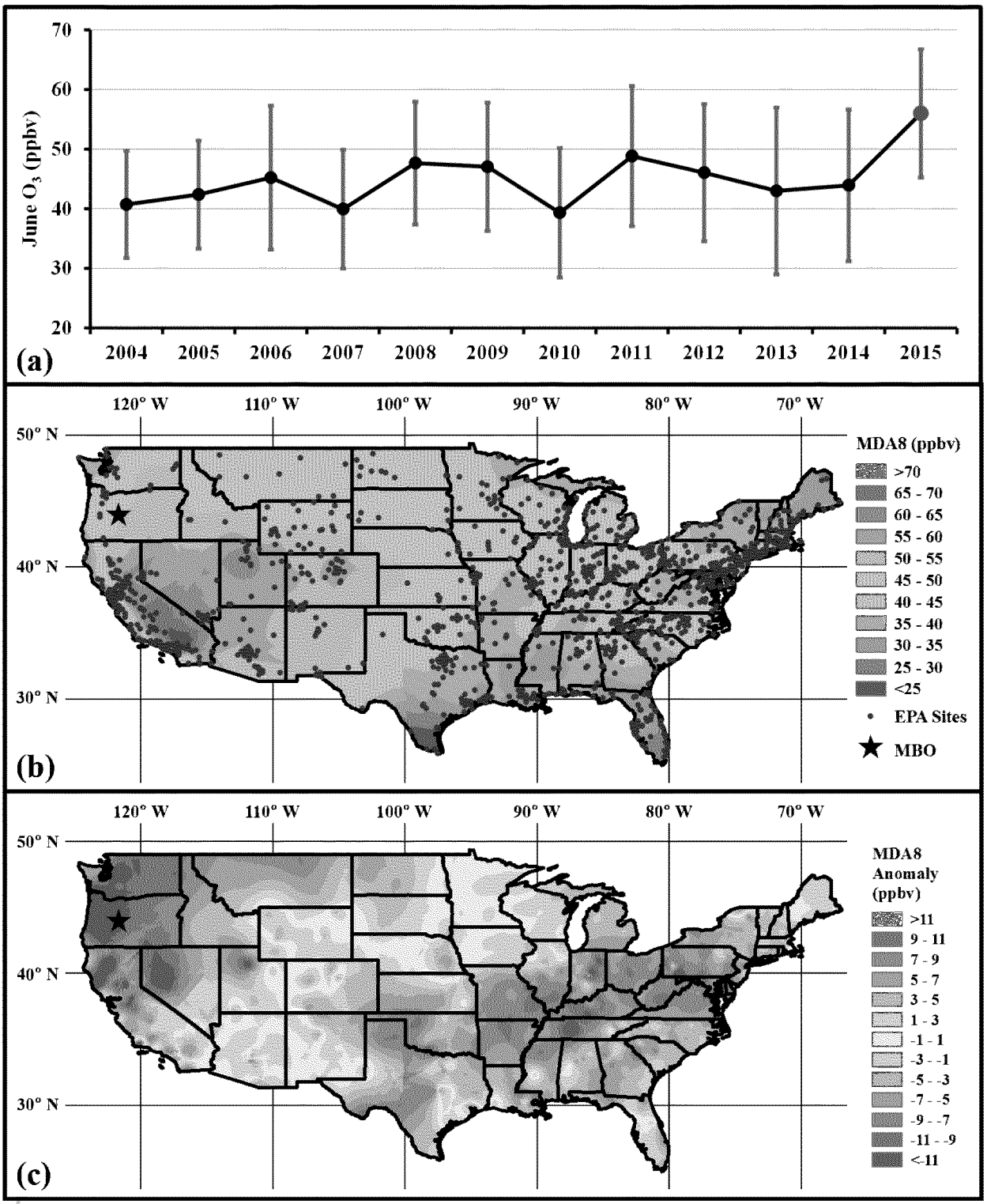

Figure 1. Data showing large changes in O_3 for June 2015. (a) Average of all O_3 data from MBO for June for 2004–2015 (the vertical bars show 1σ of the hourly values); (b) June 2015 mean MDA8 from EPA AQS stations; (c) June 2015 MDA8 anomaly relative to previous 5 years. In Figures 1b a star is used to show location of the MBO and EPA AQS sites are shown with dots.

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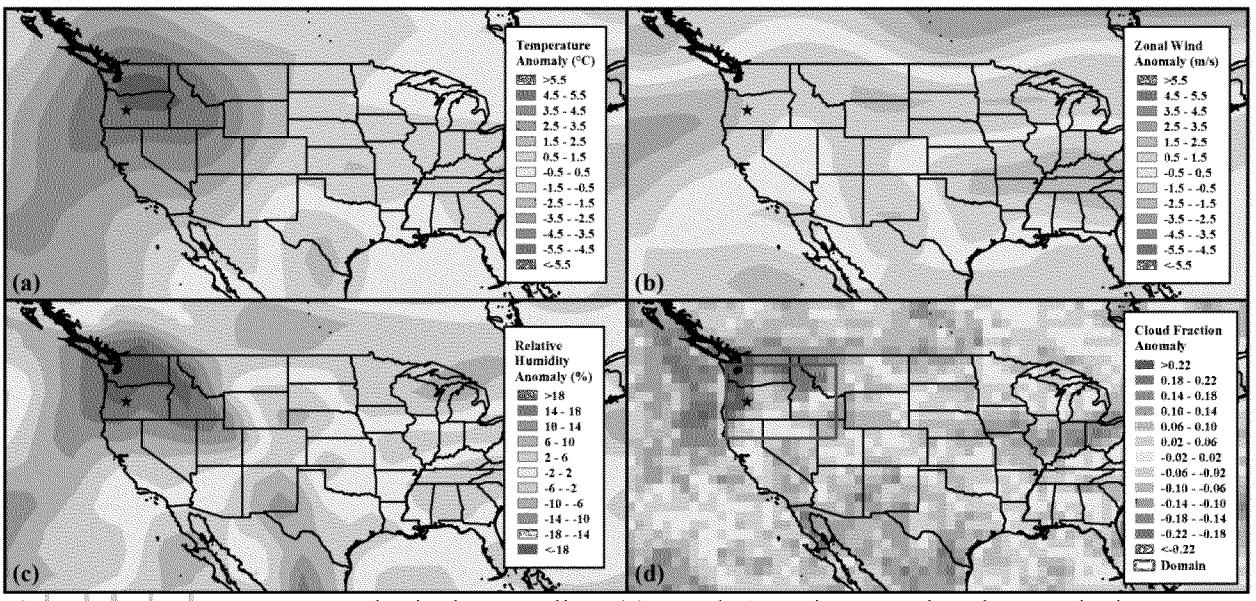

Figure 2. June 2015 meteorological anomalies: (a) North American Regional Reanalysis (NARR) 850 mbar temperature anomaly; (b) NARR 850 mbar zonal wind anomaly; (c) NARR 850 mbar RH anomaly; (d) AIRS daytime cloud fraction anomaly.

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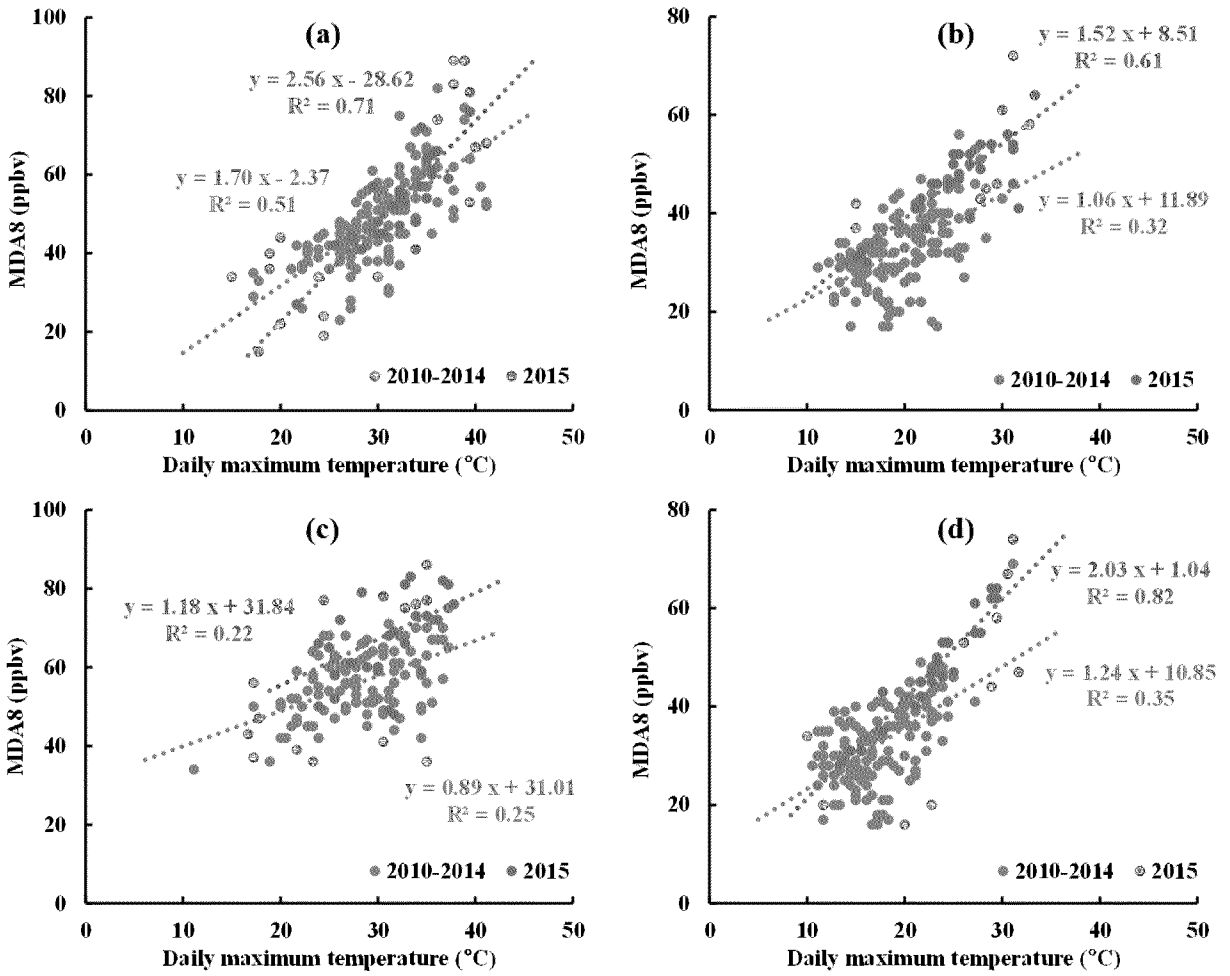

Figure 3. MDA8 vs daily maximum temperature for individual days in June 2010–2014 (blue) and June 2015 (red) for (a) Sacramento, CA (AQS id: 06-067-0006); (b) Portland, OR (AQS id: 41-005-0004); (c) Salt Lake City, UT (AQS id: 49-035-3006); and (d) Seattle, WA (AQS id: 53-033-0023).

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From: Joseph Jakuta
Location: https://global.gotomeeting.com/join/ Ex. 6
Importance: Normal
Subject: OTC Modeling Committee
Start Date/Time: Tue 11/21/2017 6:00:00 PM
End Date/Time: Tue 11/21/2017 7:30:00 PM
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US EPA_2016_Technical Support Document (TSD) Updates to Emissions Inventories for the.pdf
OTC Mobile Charge 171102.docx
OTC SAS Charge 171102.docx

;;
Dear OTC/MANE-VU Committees,
You are all being invited to the Modeling Committee call to hear a discussion with OAQPS staff concerning the 2023 modeling conducted in regards to ozone transport obligations. If you have any specific questions you would like to see addressed during the discussion please email them to me before noon on Monday.
Agenda

1. EPA Discussion of 2023 Modeling
2. OTC Modeling Committee Business

a. Fall Meeting – SAS/Mobile Charges Impact
b. EMF Training
c. 2016 Inventory Development
d. 2011 Platform Status

i. Inventory Updates
ii. 2023 Source Tag Modeling
iii. TSD

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Charge to the Mobile Source Committee to Pursue Potential Strategies for Regional Attainment of Ozone National Ambient Air Quality Standards

The Ozone Transport Commission (OTC) directs the Executive Staff and the OTC Mobile Source Committee to perform technical analyses to help OTC states develop legally supportable, cost-effective strategies to achieve emissions reductions of ozone-forming pollutants from mobile sources and satisfy Clean Air Act requirements. The goal is to identify potential strategies for consideration by the OTC.

This goal should be met by completing the following by April 2018 to support potential actions at the 2018 Spring OTC Meeting. To the extent that the Chair of the Mobile Source Committee feels that additional time is needed to complete a task, then a policy relevant briefing may be provided to the Air Directors, in the April 2018 timeframe, and the task may be finalized by the 2018 Fall OTC Meeting:

(1) Develop a tool kit of educational materials for use by OTC states in idling outreach efforts, with a focus on materials that are missing from existing tool kits.

(2) Calculate and document emissions reductions inside and outside of the Ozone Transport Region from the recommended mobile Good Neighbor SIP strategies as formalized in the Good Neighbor SIP Resolution for use in photochemical modeling and develop recommendations for additional strategies for consideration. To align with deadlines within the Clean Air Act this work should be completed by the Spring Meeting.

(3) Provide analysis and briefings to the Air Directors on critical federal and state strategies that may be needed for attaining and maintaining the 2015 ozone standard including, but not limited to, The Tier 3 Vehicle and Fuels program, EPA's implementation of the MSTRS (Mobile Source Technical Review Subcommittee) Port Workgroup's recommendations and tighter standards for heavy-duty diesel vehicles.

(4) Provide simple updates to the Commission on individual state progress on, SmartWay®, port initiatives, implementation of improved idling programs, state electric and zero emission vehicle initiatives, the Volkswagen settlement and DERA (Diesel Emission Reduction Act) activities. Updates to be provided at both the Spring and Fall Meetings.

Additionally, if new information becomes available, at the direction of the Mobile Source Committee Chair, research and analyze additional strategies that reduce mobile source emissions in a cost effective manner, employing available emission inventory estimates.

The other committees of the OTC are directed to provide whatever assistance is needed to the Mobile Source Committee in carrying out this Charge.

Adopted by the Commission on DATE

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Charge to the Stationary and Area Sources Committee to Pursue Potential Strategies for Regional Attainment of the 2008 and 2015 Ozone National Ambient Air Quality Standards

The Ozone Transport Commission (OTC) directs the Executive Staff and the OTC Stationary and Area Sources (SAS) Committee to perform technical analyses to help OTC states pursue legally supportable cost-effective strategies to achieve reductions of ozone-forming pollutants and satisfy Clean Air Act requirements. The goal is to identify potential strategies for consideration and action by the OTC. This goal should be met by completing the following by April 2018 to support potential actions at the 2018 Spring OTC Meeting. To the extent that the Chair of the SAS Committee feels that additional time is needed to complete a task, then a policy relevant briefing may be provided to the Air Directors, in the April 2018 timeframe, and the task may be finalized by the 2018 Fall OTC Meeting:

(1) Calculate and document emissions reductions inside and outside of the Ozone Transport Region for the recommended SAS Good Neighbor SIP strategies as formalized in the Good Neighbor SIP Resolution for use in photochemical modeling and develop recommendations for additional strategies for consideration.

(2) Provide analysis and briefings to the Air Directors on critical federal and state stationary and area source strategies that may be needed for attaining and maintaining the 2015 ozone standard including, but not limited to; EPA's Cross State Air Pollution Rule (CSAPR) Update, Section 126 Petitions submitted by Maryland, Connecticut and Delaware, and New York's small generator initiative.

The Committee shall also evaluate and make recommendations to the OTC member states of any updates to any previously developed OTC model rule that is based on a rule of the California Air Resources Board (CARB), and shall consider updating any such model rules to include any product categories or standards adopted by CARB.

Additionally, if new information becomes available, at the direction of the Stationary and Area Source Committee Chair, research and analyze additional strategies that reduce stationary and area source emissions in a cost effective manner, employing available emission inventory estimates.

The other committees of the OTC are directed to provide whatever assistance is needed to the Stationary and Area Sources Committee in carrying out this Charge.

Adopted by the Commission on DATE

Technical Support Document (TSD)

Additional Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023

October, 2017

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Air Quality Assessment Division

Contacts:
Alison Eyth, Jeff Vukovich

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Acronyms

AE5	CMAQ Aerosol Module, version 5, introduced in CMAQ v4.7
AE6	CMAQ Aerosol Module, version 6, introduced in CMAQ v5.0
AEO	Annual Energy Outlook
BAFM	Benzene, Acetaldehyde, Formaldehyde and Methanol
BEIS	Biogenic Emissions Inventory System
BELD	Biogenic Emissions Landuse Database
Bgal	Billion gallons
BPS	Bulk Plant Storage
BTP	Bulk Terminal (Plant) to Pump
C1/C2	Category 1 and 2 commercial marine vessels
C3	Category 3 (commercial marine vessels)
CAEP	Committee on Aviation Environmental Protection
CAIR	Clean Air Interstate Rule
CAMD	EPA's Clean Air Markets Division
CAMx	Comprehensive Air Quality Model with Extensions
CAP	Criteria Air Pollutant
CARB	California Air Resources Board
CB05	Carbon Bond 2005 chemical mechanism
CBM	Coal-bed methane
CEC	North American Commission for Environmental Cooperation
CEMS	Continuous Emissions Monitoring System
CEPAM	California Emissions Projection Analysis Model
CISWI	Commercial and Industrial Solid Waste Incinerators
Cl	Chlorine
CMAQ	Community Multiscale Air Quality
CMV	Commercial Marine Vessel
CO	Carbon monoxide
CSAPR	Cross-State Air Pollution Rule
CWFIS	Canadian Wildland Fire Information System
E0, E10, E85	0%, 10% and 85% Ethanol blend gasoline, respectively
EBAFM	Ethanol, Benzene, Acetaldehyde, Formaldehyde and Methanol
ECA	Emissions Control Area
EEZ	Exclusive Economic Zone
EF	Emission Factor
EGU	Electric Generating Units
EIS	Emissions Inventory System
EISA	Energy Independence and Security Act of 2007
EPA	Environmental Protection Agency
EMFAC	Emission Factor (California's onroad mobile model)
FAA	Federal Aviation Administration
FAPRI	Food and Agriculture Policy and Research Institute
FASOM	Forest and Agricultural Section Optimization Model
FCCS	Fuel Characteristic Classification System
FEPS	Fire Emission Production Simulator
FF10	Flat File 2010
FINN	Fire INventory from NCAR
FIPS	Federal Information Processing Standards

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FHWA	Federal Highway Administration
HAP	Hazardous Air Pollutant
HCl	Hydrochloric acid
HDGHG	Heavy-Duty Vehicle Greenhouse Gas
Hg	Mercury
HMS	Hazard Mapping System
HPMS	Highway Performance Monitoring System
HWC	Hazardous Waste Combustion
HWI	Hazardous Waste Incineration
ICAO	International Civil Aviation Organization
ICI	Industrial/Commercial/Institutional (boilers and process heaters)
ICR	Information Collection Request
IDA	Inventory Data Analyzer
I/M	Inspection and Maintenance
IMO	International Marine Organization
IPAMS	Independent Petroleum Association of Mountain States
IPM	Integrated Planning Model
ITN	Itinerant
LADCO	Lake Michigan Air Directors Consortium
LDGHG	Light-Duty Vehicle Greenhouse Gas
LPG	Liquefied Petroleum Gas
MACT	Maximum Achievable Control Technology
MARAMA	Mid-Atlantic Regional Air Management Association
MATS	Mercury and Air Toxics Standards
MCIP	Meteorology-Chemistry Interface Processor
Mgal	Million gallons
MMS	Minerals Management Service (now known as the Bureau of Energy Management, Regulation and Enforcement (BOEMRE)
MOVES	Motor Vehicle Emissions Simulator
MSA	Metropolitan Statistical Area
MSAT2	Mobile Source Air Toxics Rule
MTBE	Methyl tert-butyl ether
MWRPO	Mid-west Regional Planning Organization
NCD	National County Database
NEEDS	National Electric Energy Database System
NEI	National Emission Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NIF	NEI Input Format
NLCD	National Land Cover Database
NLEV	National Low Emission Vehicle program
nm	nautical mile
NMIM	National Mobile Inventory Model
NOAA	National Oceanic and Atmospheric Administration
NODA	Notice of Data Availability
NONROAD	EPA model for estimation of nonroad mobile emissions
NO_X	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review

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OAQPS	EPA's Office of Air Quality Planning and Standards
OHH	Outdoor Hydronic Heater
OTAQ	EPA's Office of Transportation and Air Quality
ORIS	Office of Regulatory Information System
ORD	EPA's Office of Research and Development
ORL	One Record per Line
OTC	Ozone Transport Commission
PADD	Petroleum Administration for Defense Districts
PF	Projection Factor, can account for growth and/or controls
PFC	Portable Fuel Container
$PM_{2.5}$	Particulate matter less than or equal to 2.5 microns
PM_{10}	Particulate matter less than or equal to 10 microns
ppb, ppm	Parts per billion, parts per million
RBT	Refinery to Bulk Terminal
RFS2	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RICE	Reciprocating Internal Combustion Engine
RRF	Relative Response Factor
RWC	Residential Wood Combustion
RPO	Regional Planning Organization
RVP	Reid Vapor Pressure
SCC	Source Classification Code
SESQ	Sesquiterpenes
SMARTFIRE	Satellite Mapping Automated Reanalysis Tool for Fire Incident Reconciliation
SMOKE	Sparse Matrix Operator Kernel Emissions
SO_2	Sulfur dioxide
SOA	Secondary Organic Aerosol
SI	Spark-ignition
SIP	State Implementation Plan
SPDPRO	Hourly Speed Profiles for weekday versus weekend
SPPD	Sector Policies and Programs Division
TAF	Terminal Area Forecast
TCEQ	Texas Commission on Environmental Quality
TOG	Total Organic Gas
TSD	Technical support document
ULSD	Ultra Low Sulfur Diesel
USDA	U. S. Department of Agriculture
VOC	Volatile organic compound
VMT	Vehicle miles traveled
VPOP	Vehicle Population
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting Model

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1 Introduction

In support of an analysis of the transport of ozone as it relates to the 2008 Ozone National Ambient Air Quality Standards (NAAQS), the U.S. Environmental Protection Agency (EPA) developed an air quality modeling platform based on the 2011 National Emissions Inventory (NEI), version 2 (2011NEIv2) with updates. The air quality modeling platform consists of all the emissions inventories and ancillary data files used for emissions modeling, as well as the meteorological, initial condition, and boundary condition files needed to run the air quality model. The emissions modeling component of the modeling platform includes the emission inventories, the ancillary data files, and the approaches used to transform inventories for use in air quality modeling. The emissions modeling platform that corresponded to the air quality modeling platform for ozone transport related to the 2008 ozone NAAQS is known as the updated 2011v6.3 platform.

This document focuses on the updated 2011v6.3 platform used to support analyses of transport of ozone related to the 2008 Ozone NAAQS. Much of the year 2011 data from the 2011v6.3 platform was unchanged for this updated platform and therefore the platform was not given a new number, although the future year of 2023 was used for this analysis as compared to 2017 used for the original 2011v6.3 platform in support of the Final Cross-State Air Pollution Rule (CSAPR) Update (https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update). For more information on the *original* 2011v6.3 platform and on any sectors or modeling techniques unchanged in this analysis, see the technical support document (TSD) *Preparation of Emission Inventories for the version 6.3, 2011 Emissions Modeling Platform* (EPA, 2016a), from August, 2016 available from EPA's Air Emissions Modeling web page for the version 6.3 platform: https://www.epa.gov/air-emissions-modeling/2011-version-63-platform. This web page also includes a link to the TSD *Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023* (EPA, 2016b) that describes an earlier iteration of 2011 and 2023 emission cases that were released for public comment in January, 2017 (https://www.regulations.gov/document?D=EPA-HQ-OAR-2016-0751-0001). The updated platform described in *this document* includes additional updates as compared to the previously released and documented versions of the 2011v6.3 platform.

This 2011-based modeling platform includes all criteria air pollutants (CAPs) and precursors and the following hazardous air pollutants (HAPs): chlorine (Cl), hydrogen chloride (HCl), benzene, acetaldehyde, formaldehyde and methanol. The latter four HAPs are also abbreviated as BAFM. The air quality model used for this study is the Comprehensive Air Quality Model with Extensions (CAMx) model (http://www.camx.com/), version 6.40. However, emissions are first processed into a format compatible with for the Community Multiscale Air Quality (CMAQ) model (https://www.epa.gov/cmaq), version 5.0.2, and those emissions are converted into CAMx-ready formats.

Both CAMx and CMAQ support modeling ozone (O_3) and particulate matter (PM), and require as input hourly and gridded emissions of chemical species that correspond to CAPs and specific HAPs. The chemical mechanism used by CAMx for this platform is called Carbon Bond version 6 revision 4 (CB6r4). This version includes updated reactions, but the emissions species needed to drive this version are unchanged from the Carbon Bond version 6 revision 2 (CB6r2), which includes important reactions for simulating ozone formation, nitrogen oxides (NOx) cycling, and formation of secondary aerosol species (Hildebrant Ruiz and Yarwood, 2013). CB6 provides several revisions to the previous carbon bond version (CB05) through inclusion of four new explicit organic species: benzene, propane, acetylene and acetone, along with updates to reaction chemistry for those species and several other volatile organic chemicals (VOCs).

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This update to the 2011v6.3 platform consists of two 'complete' emissions cases: the 2011 base case (i.e., 2011en_cb6v2_v6), and the 2023 base case (i.e., 2023en_cb6v2_v6), plus a source apportionment case with the same emissions as the 2023 base case but processed for ozone source apportionment. In the case abbreviations, 2011 and 2023 are the years represented by the emissions; the "e" stands for evaluation, meaning that year-specific data for fires and electric generating units (EGUs) are used; and the "n" represents that an iteration of emissions for the 2011-based modeling platform (i.e., the first case for the 2011 platform was 2011ea, the second was 2011eb, and so on). The purpose of the 2011 base case is to represent the year 2011 in a manner consistent with the methods used in corresponding future-year cases, including the 2023 future year base case, as well as any additional future year control and source apportionment cases. Table 1-1 provides more information on these emissions cases. This document describes any changes made since the original 2011v6.3 platform that included the cases 2011ek and 2017ek, thus any changes included in the cases 2011el and 2023el are described in addition to changes made for 2011en and 2023en.

For this application, the outputs from the 2011 base case are used in conjunction with the outputs from the 2023 base case in the relative response factor (RRF) calculations to identify future areas of nonattainment. For more information on the use of RRFs and air quality modeling, see "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM 2.5, and Regional Haze," available from http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf.

Table 1-1. List of cases in this update to the 2011 Version 6.3 Emissions Modeling Platform for 2023

Case Name	Abbreviation	Description
2011 base case	2011en_cb6v2_v6	2011 case relevant for air quality model evaluation purposes and for computing relative response factors with 2023 scenario(s). Uses 2011NEIv2 along with some other inventory data, with hourly 2011 continuous emissions monitoring system (CEMS) data for electric generating units (EGUs), hourly onroad mobile emissions, and 2011 day-specific wild and prescribed fire data. Wildfire inventories for Canada and Mexico were also included.
2023 base case	2023en_cb6v2_v6	2023 "base case" scenario, representing the best estimate for 2023 that incorporates estimates of the impact of current "on-the-books" regulations.
2023 source apportionment case	2023en_ussa_cb6v2_v6_11g	2023 emissions equivalent to those in the 2023el_cb6v2_v6 case, except that the emission sources are tagged according to their origin by state or sector.

All of the above cases use the same version of the 2011 meteorology and the cases are sometimes referred to with "_11g" after the emissions portion of the case name where "g" corresponds to the 7th configuration of the meteorological modeling platform, although the configuration is not exclusive to modeling of the year 2011. A special version of the 2023en_cb6v2_v6 case called 2023en_ussa_cb6v2_v6_11g was prepared for use with the CAMx OSAT/APCA feature that allowed the contribution of 2023 base case NOx and VOC emissions from all sources in each state to projected 2023 ozone concentrations at air quality monitoring sites to be quantified. The emissions for the case are equivalent to those in the 2023el_cb6v2_v6 case, except that the emission sources are tagged according to their origin by state or sector. The steps for setting up the 2023el_ussa_cb6v2_v6 source apportionment case include:

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1) prepare files for the source groups to track (e.g., anthropogenic emissions from each state, non-geographic sector-specific tags for biogenic, fugitive dust, fire, and non-U.S. emissions);
2) run all sectors in Sparse Matrix Operator Kernel Emissions (SMOKE) using the specified source groups (note that emissions for both source apportionment and for a regular CAMx run can be developed simultaneously);
3) create CAMx point source files for source groups tracked only by sector;
4) convert SMOKE outputs to CAMx point source files using the tags assigned by SMOKE; and
5) merge all of the point source files together into a single CAMx mrgpt file for each day.

More information on processing for source apportionment is available with the scripts provided for the 2011v6.3 platform at ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/.

The emissions data in this platform are primarily based on the 2011NEIv2 for point sources, nonpoint sources, commercial marine vessels (CMV), nonroad mobile sources and fires. The onroad mobile source emissions are similar to those in the 2011NEIv2, but were generated using the released 2014a version of the Motor Vehicle Emissions Simulator (MOVES2014a) (http://www.epa.gov/otaq/models/moves/).

The primary emissions modeling tool used to create the air quality model-ready emissions was the SMOKE modeling system (https://www.cmascenter.org/smoke/). SMOKE version 3.7 was used to create emissions files for a 12-km national grid that includes all of the contiguous states "12US2," shown in Figure 3-1. Electronic copies of the data used as input to SMOKE for the cases for this update to the 2011v6.3 platform are available from the corresponding section of the EPA Air Emissions Modeling website, https://www.epa.gov/air-emissions-modeling/2011-version-63-platform.

The gridded meteorological model used for the emissions modeling was developed using the Weather Research and Forecasting Model (WRF, https://www.mmm.ucar.edu/weather-research-and-forecasting-model) version 3.4, Advanced Research WRF core (Skamarock, et al., 2008). The WRF Model is a mesoscale numerical weather prediction system developed for both operational forecasting and atmospheric research applications. The WRF model was run for 2011 over a domain covering the continental U.S. at a 12km resolution with 35 vertical layers. The data output from WRF were collapsed to 25 layers prior to running the emissions and air quality models. The run for this platform included high resolution sea surface temperature data from the Group for High Resolution Sea Surface Temperature (GHRSST) (see https://www.ghrsst.org/) and is given the EPA meteorological case label "11g" and are consistent with those used for the original 2011v6.3 platform cases.

This document contains six sections. Section 2 describes the changes made to the 2011 inventories input to SMOKE in this update to the 2011v6.3 platform. Section 3 describes the updates to emissions modeling and the ancillary files used to convert the emission inventories into air quality model-ready formats. Section 4, describes the development of the 2023 inventory (projected from 2011). Data summaries comparing the 2011 and 2023 base cases are provided in Section 5. Section 6 provides references.

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2 2011 Emission Inventories and Approaches

This section describes the updates to the 2011 emissions data as compared to the 2011 case known as 2011ek_cb6v2_v6 in the 2011v6.3 platform (EPA, 2016a). Table 2-1 presents the sectors in this update to the 2011 platform that differ from the original 2011v6.3 plaform. The platform sector abbreviations are provided in italics. These sector abbreviations are used in the SMOKE modeling scripts, inventory file names, and throughout the remainder of this document. The remaining sectors for which 2011 emissions are unchanged from those in the 2011ek case are listed below in Table 2-2. Documentation for these sectors, plus additional information on the updated sectors, can be found in the original 2011v6.3 TSD (EPA, 2016a).

Table 2-1. Platform sectors updated since the original 2011v6.3 emissions modeling platform

Platform Sector: ***abbreviation***	**Description and resolution of the data input to SMOKE**
Biogenics: ***beis***	Emissions from natural vegetative sources. Minor corrections made to BELD4.1 landuse data used as input to BEIS3.61 (*updated in 2011en).*
Category 1 and 2 CMV: ***cmv_c1c2***	*New sector in 2011en:* Category 1 (C1) and category 2 (C2) commercial marine vessel (CMV) emissions sources using diesel fuel from the 2011NEIv2 nonpoint inventory. County and annual resolution; (*2011el included updated CMV emissions for California; emissions unchanged in 2011en but improved spatial surrogate is used)*
Category 3 CMV: ***cmv***	*New sector in 2011en:* Category 3 (C3) commercial marine vessel (CMV) emissions sources using residual fuel from the 2011NEIv2 nonpoint inventory including emissions in state and federal waters. In 2011en, this sector includes the ECA inventory for non-US, non-Canada waters that was formerly part of the othpt sector. County and annual resolution *(emissions totals unchanged from 2011el but new sector allows for plume rise treatment in 2011en).*
Non-point: ***nonpt***	Nonpoint sources not included in other sectors. 2011en includes a minor reduction to VOC emissions in New York state for Commercial/Industrial and Residential Natural Gas: Boilers and IC Engines (*updated in 2011en).*
Nonroad: ***Nonroad***	Nonroad mobile source emissions based on 2011NEIv2. Inventory data consistent in 2011el and 2011en. In 2011en, temporal profiles for construction, lawn/garden (residential and commercial), and agriculture sources were updated (*temporal profiles updated in 2011en).*
Onroad: ***onroad***	Onroad mobile source gasoline and diesel vehicles from parking lots and moving vehicles. Includes exhaust, extended idle, auxiliary power units, evaporative, permeation, refueling, and brake and tire wear. For all states, except California and Texas, based on monthly MOVES emissions tables produced by MOVES2014a. California emissions are based on Emission Factor (EMFAC) *and were updated in 2011el from the original 2011v6.3platform*. MOVES emissions for Texas provided by TCEQ for year 2012 were backcast to year 2011. MOVES-based emissions computed for each hour and model grid cell using monthly and annual activity data (e.g., VMT, vehicle population). *In 2011el, ethanol-85 usage in 2011 VMT was reduced to reflect actual percentage of E-85 used (changes in 2011el but none in 2011en).*

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Platform Sector: *abbreviation*	Description and resolution of the data input to SMOKE
EGU point sources: ***ptegu***	Point sources for electric generating units. In 2011en, minor changes were made to stack parameters, locations, and Continuous Emissions Monitoring System (CEMS) matching were made based on comments. Some sources moved into this sector from ptnonipm and out of the sector to ptnonipm also based on comments (*inventory and temporal profiles updated in 2011en).*
Non-US. fires: ***ptfire_mxca***	*New Sector added in 2011el:* Point source day-specific wildfires and prescribed fires for 2011 provided by Environment Canada with data for missing months and for Mexico filled in using fires from the Fire INventory from NCAR (FINN) fires (*emissions unchanged in 2011en).*
Non-EGU point sources: ***ptnonipm***	Point sources other than EGU and oil and gas production-related sources form 2011NEIv2. *In 2011en*, minor changes were made to stack parameters, locations, and CEMS matching were made based on comments. Some sources moved into this sector from ptegu and out of the sector to ptegu also based on comments (*updates specific to 2011en).*
Other point sources not from the 2011 NEI: ***othpt***	Offshore U.S. oil platforms from 2011NEIv2, plus point sources from Canada's **2013** inventory and Mexico's 2008 inventory *projected to 2011*, annual resolution. The *othpt* section was processed as a monthly sector because the 2013 Canadian airport point source inventory was at the monthly resolution. Also, for 2011en the ECA C3 for non-US/non-Canada CMV was moved into *cmv_c3 (2013 inventory for Canada is new in 2011en).*
Other area-fugitive dust not from 2011 NEI: ***othafdust***	Annual fugitive dust sources from Canada's **2013** inventory at province resolution. Export fraction and precipitation adjustments applied to this inventory to produce hourly, gridded emissions (*2013 for Canada is new in 2011en).*
Other non-NEI nonpoint and nonroad: ***othar***	Monthly year **2013** Canada (province resolution) and Mexico's 2008 nonpoint and nonroad mobile inventories *projected to 2011* (municipio resolution). Updated Canadian spatial surrogates along with population surrogate for Mexico (*new surrogates in 2011en and 2013 for Canada).*
Other non-NEI onroad sources: ***othon***	Monthly year **2013** Canada (province / annual resolution) onroad mobile inventories and *MOVES-Mexico emissions for 2011* (municipio / monthly resolution). Updated Canadian spatial surrogates and population surrogate for Mexico used (*new surrogates in 2011en and 2013 for Canada).*

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Table 2-2. Platform sectors for which 2011 emissions are unchanged since the original 2011v6.3 emissions modeling platform

Platform Sector: ***abbreviation***	**NEI Data Category**	**Description and resolution of the data input to SMOKE**
Area fugitive dust: ***afdust***	Nonpoint	PM_{10} and $PM_{2.5}$ fugitive dust sources from the 2011NEIv2 nonpoint inventory; including building construction, road construction, agricultural dust, and road dust. However, unpaved and paved road dust emissions differ from the NEI in that they do not have a precipitation adjustment. Instead, the emissions modeling adjustment applies a transport fraction and a meteorology-based (precipitation and snow/ice cover) zero-out. County and annual resolution. *Note: 2011 afdust emissions are unchanged from 2011ek and 2023 afdust emissions are unchanged from 2023el.*
Agricultural: ***ag***	Nonpoint	NH_3 emissions from 2011NEIv2 nonpoint livestock and fertilizer application, county and annual resolution. *Note: 2011 ag emissions are unchanged from 2011ek and 2023 ag emissions are unchanged from 2023el.*
Agricultural fires: ***agfire***	Nonpoint	2011NEIv2 agricultural fire sources, except for Missouri, which reverted to 2011NEIv1 based on comments. County and monthly resolution. *Note: agfire emissions are constant in the base and future years and unchanged from 2011ek.*
Nonpoint source oil and gas: ***np_oilgas***	Nonpoint	2011NEIv2 nonpoint sources from oil and gas-related processes with specific adjustments based on comments. County and annual resolution. Includes updates in Utah, and corrects sources in WRAP areas so that they are no-integrate and use WRAP speciation profiles. Additionally, new Texas inventory supplied by TCEQ, and modifications to Oklahoma (VOC-only changes) and West Virginia (SO2-only changes) inventories due to NODA comments. *Note: 2011 np_oilgas emissions are unchanged from 2011ek, but 2023 emissions have been updated in 2023en based on comments.*
Point source fires: ***ptfire***	Fires	Point source day-specific wildfires and prescribed fires for 2011 computed using SMARTFIRE2, except for Georgia and Florida-submitted emissions. Consistent with 2011NEIv2. *Note: ptfire emissions are constant in the base and future years and unchanged from 2011ek.*
Point source oil and gas: ***pt_oilgas***	Point	2011NEIv2 point sources that include oil and gas production emissions processes with specific updates to emissions and stack parameters based on comments and updates to control program order of precedence. Annual resolution. *Note: 2011pt_oilgas emissions are unchanged from 2011ek, but 2023 emissions have been updated in 2023en based on comments.*
Locomotives: ***rail***	Nonpoint	Rail locomotives emissions from the 2011NEIv2 with specific adjustments based on comments. *Note: 2011 rail emissions are unchanged from 2011ek and 2023 rail emissions are unchanged from 2023el.*
Residential Wood Combustion: ***rwc***	Nonpoint	2011NEIv2 NEI nonpoint sources with Residential Wood Combustion (RWC) processes. County and annual resolution. *Note: 2011 rwc emissions are unchanged from 2011ek and 2023 emissions are unchanged from 2023el.*

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The emission inventories in SMOKE input format for the 2011 base case are available from the EPA's Air Emissions Modeling website for the version 6.3 platform, https://www.epa.gov/air-emissions-modeling/2011-version-63-platform. The README_2011en_2023en_package.txt file indicates the particular zipped files associated with each platform sector. The specific updated inventories for this platform can be found in the directories ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/2011en_update/ and ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/2023en_update/. Files in the ancillary_data directory and the 12km spatial surrogates have been updated to include all of the files for this update of the platform.

A number of reports (i.e., summaries) are available with the data files for the updated 2011v6.3 platform in ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/reports/2011en_and_2023en/. The types of reports include state summaries of inventory pollutants and model species by modeling platform sector, county annual totals by modeling platform sector, daily NOx and VOC emissions by sector and total, and state-SCC-sector summaries. A comparison of the complete list of inventory files, ancillary files, and parameter settings with those for the 2011v6.3 platform is also available in *2011v6.3_ek_el_en_case_inputs.xlsx*.

The remainder of Section 2 provides details about the data contained in each of the 2011 platform sectors that were modified from the original 2011v6.3 platform.

2.1 2011 point sources (ptegu, ptnonipm, pt_oilgas)

Point sources are sources of emissions for which specific geographic coordinates (e.g., latitude/longitude) are specified, as in the case of an individual facility. A facility may have multiple emission release points that may be characterized as units such as boilers, reactors, spray booths, kilns, etc. A unit may have multiple processes (e.g., a boiler that sometimes burns residual oil and sometimes burns natural gas). With a couple of minor exceptions, this section describes only NEI point sources within the contiguous U.S. The NEI is split into three point sectors: the EGU sector for non-peaking units (ptegu), point source oil and gas extraction-related emissions (pt_oilgas) – including off-shore oil platforms, and the remaining non-EGU sector (ptnonipm) sector. The EGU emissions are split out from the other sources to facilitate the use of distinct SMOKE temporal processing and future-year projection techniques. The oil and gas sector emissions (pt_oilgas) were processed separately for summary tracking purposes and distinct future-year projection techniques from the remaining non-EGU emissions (ptnonipm).

The ptnonipm and pt_oilgas sector emissions were provided to SMOKE as annual emissions. For those ptegu sources with CEMS data (that could be matched to the 2011NEIv2), 2011 hourly CEMS NO_X and SO_2 emissions were used rather than NEI emissions, and for all other pollutants, annual emissions were used as-is from the NEI, but were allocated to hourly values using heat input CEMS data. EGUs without CEMS are allocated to hourly data base on IPM region- and pollutant-specific temporal profiles as discussed in Section 3.3.3.

The inventory pollutants processed through SMOKE for all point source sectors were: CO, NO_X, VOC, SO_2, ammonia (NH_3), PM_{10}, and $PM_{2.5}$ and the following HAPs: HCl (pollutant code = 7647010), and Cl (code = 7782505). The inventory BAFM from these sectors was not used, instead VOC was speciated to these pollutants without any use (i.e., integration) of the VOC HAP pollutants from the inventory.

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Minor updates were made to some sources in the ptnonipm sector to address comments on the January, 2017 Notice of Data Availability (NODA) as follows:

1. Added four Connecticut municipal waste combustor (MWC) units to ptnonipm from ptegu, and removed two Wheelabrator Bridgeport units to be moved to ptegu. For the new ptnonipm sources, blanked out the ORIS IDs and NEEDS_ID fields.
2. NC closures from pre2011_nc_ptnonipm_closures.xlsx were applied to ptnonipm. We confirmed that all of those facilities/units listed were in ptnonipm, and not ptegu/pt_oilgas.

Updates were made to some sources in the ptegu sector to address comments on the NODA and other updated data updates as follows:

1. Updated some FIPS codes and latitudes/longitudes based on the information in the CEMS reporting data.
2. Updated stack parameters as specified in Kansas NODA comments.
3. For Unit 21257713 in Texas (IPM_YN = 7097_B_BLR1; former ORIS facility 7097, ORIS boiler **1), blanked out ORIS IDs to make that unit a non-CEM source so that inventory emissions are used instead of CEMs, in particular for SO2.
4. Moved four Connecticut MWCs to ptnonipm, and added two Wheelabrator Bridgeport units from ptnonipm.

2.1.1 EGU sector (ptegu)

The ptegu sector contains emissions from EGUs in the 2011NEIv2 point inventory that could be matched to units found in the NEEDS v5.16 database that includes the units for which the Integrated Planning Model (IPM) predicts emissions. The ptegu sector indication is used in this modeling even though IPM was not used to derive the future year emissions. In the SMOKE point flat file, emission records for sources that have been matched to the NEEDS database have a value filled into the IPM_YN column. Many of these matches are stored within the Emission Inventory System (EIS) that is used to create the NEI. In some cases, it was difficult to match the sources between the databases due to different facility names in the two data systems and due to differences in how the units are defined, thereby resulting in matches that are not always one-to-one. Some additional matches were made in the modeling platform to accommodate some of these situations as described later in this section.

Some units in the ptegu sector are matched to CEMS data via ORIS facility codes and boiler ID. For matched units, SMOKE replaces the 2011 emissions of NO_X and SO_2 with the CEMS emissions, thereby ignoring the annual values specified in the NEI. For other pollutants, the hourly CEMS heat input data are used to allocate the NEI annual emissions to hourly values. All stack parameters, stack locations, and SCC codes for these sources come from the NEI. Because these attributes are obtained from the NEI, the chemical speciation of VOC and $PM_{2.5}$ for the sources is selected based on the SCC or in some cases, based on unit-specific data. If CEMS data exists for a unit, but the unit is not matched to the NEI, the CEMS data for that unit is not used in the modeling platform. However, if the source exists in the NEI and is not matched to a CEMS unit, the emissions from that source are still modeled using the annual emission value in the NEI. The EIS stores many matches from EIS units to the ORIS facility codes and boiler IDs used to reference the CEMS data. Some additional matches were made in the modeling platform as described later in this section.

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In the SMOKE point flat file, emission records for point sources matched to CEMS data have values filled into the ORIS_FACILITY_CODE and ORIS_BOILER_ID columns. The CEMS data in SMOKE-ready format is available at http://ampd.epa.gov/ampd/ near the bottom of the "Prepackaged Data" tab. Many smaller emitters in the CEMS program are not identified with ORIS facility or boiler IDs that can be matched to the NEI due to inconsistencies in the way a unit is defined between the NEI and CAMD datasets, or due to uncertainties in source identification such as inconsistent plant names in the two data systems. Also, the NEEDS database of units modeled by IPM includes many smaller emitting EGUs that are not included in the CAMD hourly CEMS programs. Therefore, there will be more units in the NEEDS database than have CEMS data. The temporalization of EGU units matched to CEMS is based on the CEMS data in the base and future years are based on the base year CEMS data for those units, whereas regional profiles are used for the remaining units. More detail can be found in Section 3.3.3.

Matches between the NEI and NEEDS were identified by identifying units in IPM outputs that were not yet matched to NEI data, and by looking for units identified in the NEI with facility type codes identifying them as EGUs or facility names that indicated they were EGUs. In each case, priority was given to units with larger emissions (e.g., > 300TPY of NO_x or SO_2). The units in each data set that did not yet have matches within the same county were compared to one another on the basis of their plant names and locations. In some cases, IDs were similar but were mismatched only due to a missing leading zero in one of the databases. In other cases, a facility level match was specified, but a unit/boiler level match was not yet identified and, therefore, the units at the facility were compared to one another on the basis of design capacity and naming. For any new matches that were found, values that represented the NEEDS IDs were filled in to the IPM_YN in the modeling platform flat files. When possible, these matches were loaded into EIS. When new matches were identified, EGUs that otherwise would have remained in the ptnonipm sector were moved to the ptegu sector.

A similar process was used to identify additional matches between the 2011NEIv2 and CEMS data. To determine whether a NEI unit matched a CEMS unit, the CEMS units were compared to facilities in the NEI that were not yet identified as a CEMS unit on the basis of their county FIPS codes, locations, and total emissions of NO_x and SO_2. Additional CEMS matches that were found were applied to the FF10 file by specifying values for ORIS_FACILITY_CODE, ORIS_BOILER_ID. Because IPM uses a concatenation of the ORIS facility code and boiler ID, values were also filled in to the IPM_YN field for these units. Many new CEMS assignments were loaded into EIS for use in future inventories. Note that SMOKE can perform matches of CEMS data down to the stack or release point-level, which is finer than unit-level.

2.1.2 Point source oil and gas sector (pt_oilgas)

The pt_oilgas sector was separated from the ptnonipm sector by selecting sources with specific NAICS codes shown in Table 2-3. The emissions and other source characteristics in the pt_oilgas sector are submitted by states, while the EPA developed a dataset of nonpoint oil and gas emissions for each county in the U.S. with oil and gas activity that was available for states to use. Nonpoint oil and gas emissions can be found in the np_oilgas sector. More information on the development of the 2011 oil and gas emissions can be found in Section 3.20 of the 2011NEIv2 TSD.

Table 2-3. Point source oil and gas sector NAICS Codes

NAICS	NAICS description
2111	Oil and Gas Extraction
2212	Natural Gas Distribution

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NAICS	NAICS description
4862	Pipeline Transportation of Natural Gas
21111	Oil and Gas Extraction
22121	Natural Gas Distribution
48611	Pipeline Transportation of Crude Oil
48621	Pipeline Transportation of Natural Gas
211111	Crude Petroleum and Natural Gas Extraction
211112	Natural Gas Liquid Extraction
213111	Drilling Oil and Gas Wells
213112	Support Activities for Oil and Gas Operations
221210	Natural Gas Distribution
486110	Pipeline Transportation of Crude Oil
486210	Pipeline Transportation of Natural Gas

2.1.3 Non-IPM sector (ptnonipm)

Except for some minor exceptions, the non-IPM (ptnonipm) sector contains the 2011NEIv2 point sources that are not in the ptegu or pt_oilgas sectors. For the most part, the ptnonipm sector reflects the non-EGU sources of the NEI point inventory; however, it is likely that some small low-emitting EGUs not matched to the NEEDS database or to CEMS data are present in the ptnonipm sector. The sector includes some ethanol plants that have been identified by EPA and require special treatment in the future cases as they are impacted by mobile source rules.

The ptnonipm sector contains a small amount of fugitive dust PM emissions from vehicular traffic on paved or unpaved roads at industrial facilities, coal handling at coal mines, and grain elevators. Sources with state/county FIPS code ending with "777" are in the 2011NEIv2 but are not included in any modeling sectors. These sources typically represent mobile (temporary) asphalt plants that are only reported for some states, and are generally in a fixed location for only a part of the year and are, therefore, difficult to allocate to specific places and days as is needed for modeling. Therefore, these sources are dropped from the point-based sectors in the modeling platform.

EPA estimates for ethanol facilities

As ethanol plants are important facilities for mobile source rules that have impact development work, the EPA developed a list of corn ethanol facilities for 2011. Ethanol facilities that were not in 2011NEIv1 were added into 2011NEIv2. Some adjustments were made to these based on comments. Locations and FIPS codes for these ethanol plants were verified using web searches and Google Earth. The EPA believes that some of these sources were not originally included in the NEI as point sources because they do not meet the 100 ton/year potential-to-emit threshold for NEI point sources. Emission rates for the ethanol plants were obtained from EPA's updated spreadsheet model for upstream impacts developed for the Renewable Fuel Standard (RFS2) rule (EPA, 2010a). Plant emission rates for criteria pollutants used to estimate impacts for years 2011 (and are assumed to be the same in the future) are given in Table 2-4.

Table 2-4. Corn Ethanol Plant Criteria Pollutant Emission Factors (grams per gallon produced)

Corn Ethanol Plant Type	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3
Dry Mill Natural Gas (NG)	2.29	0.58	0.99	0.94	0.23	0.01	0.00

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Corn Ethanol Plant Type	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3
Dry Mill NG (wet distillers grains with solubles (DGS))	2.27	0.37	0.63	0.91	0.20	0.00	0.00
Dry Mill Biogas	2.29	0.62	1.05	0.94	0.23	0.01	0.00
Dry Mill Biogas (wet DGS)	2.27	0.39	0.67	0.91	0.20	0.00	0.00
Dry Mill Coal	2.31	2.65	4.17	3.81	1.71	4.52	0.00
Dry Mill Coal (wet DGS)	2.31	2.65	2.65	2.74	1.14	2.87	0.00
Dry Mill Biomass	2.42	2.55	3.65	1.28	0.36	0.14	0.00
Dry Mill Biomass (wet DGS)	2.35	1.62	2.32	1.12	0.28	0.09	0.00
Wet Mill NG	2.35	1.62	1.77	1.12	0.28	0.09	0.00
Wet Mill Coal	2.33	1.04	5.51	4.76	2.21	5.97	0.00

Air toxic emission rates were estimated by applying toxic to VOC ratios in Table 2-5, and were multiplied by facility production estimates for 2011 and 2018 based on analyses performed for the industry characterization described in Chapter 1 of the RFS2 final rule regulatory impact analysis. For air toxics, except ethanol, the toxic-to-VOC ratios were developed using emission inventory data from the 2005 NEI (EPA, 2009a).

Table 2-5. Toxic-to-VOC Ratios for Corn Ethanol Plants

	Acetaldehyde	Acrolein	Benzene	1,3-Butadiene	Formaldehyde
Wet Mill NG	0.02580	0.00131	0.00060	2.82371E-08	0.00127
Wet Mill Coal	0.08242	0.00015	0.00048	2.82371E-08	0.00108
Dry Mill NG	0.01089	0.00131	0.00060	2.82371E-08	0.00127
Dry Mill Coal	0.02328	0.00102	0.00017	2.82371E-08	0.00119

2.2 2011 nonpoint sources (afdust, ag, agfire, np_oilgas, rwc, nonpt)

Several modeling platform sectors were created from the 2011NEIv2 nonpoint inventory. This section describes the *stationary* nonpoint sources. Locomotives, C1 and C2 CMV, and C3 CMV are also included the 2011NEIv2 nonpoint data category, but are mobile sources that are described in Sections 2.4.1 and 2.4.2 as the CMV and rail sectors, respectively. The 2011NEIv2 TSD available from https://www.epa.gov/air-emissions-inventories/2011-national-emissions-inventory-nei-documentation includes documentation for the nonpoint sector of the 2011NEIv2 Stationary nonpoint sources that were not subdivided into the afdust, ag, np_oilgas, or rwc sectors were assigned to the "nonpt" sector.

The nonpoint tribal-submitted emissions are dropped during spatial processing with SMOKE due to the configuration of the spatial surrogates. Part of the reason for this is to prevent possible double-counting with county-level emissions and also because spatial surrogates for tribal data are not currently available. These omissions are not expected to have an impact on the results of the air quality modeling at the 12-km scales used for this platform.

For the 2011en case, the only change in the nonpt sector was based on a comment from MARAMA regarding natural gas combustion SCCs in the state of New York. The *Commercial/Residential* (SCC=2103006000) and *Residential* (SCC=2104006010) *Natural Gas; Total Boilers and IC Engines* VOC emissions were both reduced by about 25% in New York state. This resulted in about a 575-ton reduction in VOC emissions.

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The following subsections describe how the sources in the 2011NEIv2 nonpoint inventory were separated into 2011 modeling platform sectors, along with any data that were updated replaced with non-NEI data.

2.2.1 Area fugitive dust sector (afdust)

The area-source fugitive dust (afdust) sector contains PM_{10} and $PM_{2.5}$ emission estimates for nonpoint SCCs identified by EPA staff as dust sources. Categories included in the afdust sector are paved roads, unpaved roads and airstrips, construction (residential, industrial, road and total), agriculture production, and mining and quarrying. It does not include fugitive dust from grain elevators, coal handling at coal mines, or vehicular traffic on paved or unpaved roads at industrial facilities because these are treated as point sources so they are properly located.

The afdust sector is separated from other nonpoint sectors to allow for the application of a "transport fraction," and meteorological/precipitation reductions. These adjustments are applied with a script that applies land use-based gridded transport fractions followed by another script that zeroes out emissions for days on which at least 0.01 inches of precipitation occurs or there is snow cover on the ground. The land use data used to reduce the NEI emissions determines the amount of emissions that are subject to transport. This methodology is discussed in (Pouliot, et al., 2010), and in "Fugitive Dust Modeling for the 2008 Emissions Modeling Platform" (Adelman, 2012). Both the transport fraction and meteorological adjustments are based on the gridded resolution of the platform (e.g., 12km grid cells); therefore, different emissions will result if the process were applied to different grid resolutions. A limitation of the transport fraction approach is the lack of monthly variability that would be expected with seasonal changes in vegetative cover. While wind speed and direction are not accounted for in the emissions processing, the hourly variability due to soil moisture, snow cover and precipitation is accounted for in the subsequent meteorological adjustment.

The sources in the afdust sector are for SCCs and pollutant codes (i.e., PM_{10} and $PM_{2.5}$) that are considered to be "fugitive" dust sources. These SCCs are provided in Table 2-6.

Table 2-6. SCCs in the afdust platform sector

SCC	SCC Description
2275085000	Mobile Sources;Aircraft;Unpaved Airstrips;Total
2294000000	Mobile Sources;Paved Roads;All Paved Roads;Total: Fugitives
2294000002	Mobile Sources;Paved Roads;All Paved Roads;Total: Sanding/Salting - Fugitives
2296000000	Mobile Sources;Unpaved Roads;All Unpaved Roads;Total: Fugitives
2296005000	Mobile Sources;Unpaved Roads;Public Unpaved Roads;Total: Fugitives
2296010000	Mobile Sources;Unpaved Roads;Industrial Unpaved Roads;Total: Fugitives
2311000000	Industrial Processes;Construction: SIC 15 - 17;All Processes;Total
2311010000	Industrial Processes;Construction: SIC 15 - 17;Residential;Total
2311020000	Industrial Processes;Construction: SIC 15 - 17;Industrial/Commercial/Institutional;Total
2311030000	Industrial Processes;Construction: SIC 15 - 17;Road Construction;Total
2311040000	Industrial Processes;Construction: SIC 15 - 17;Special Trade Construction;Total
2325000000	Industrial Processes;Mining and Quarrying: SIC 14;All Processes;Total
2325020000	Industrial Processes;Mining and Quarrying: SIC 14;Crushed and Broken Stone;Total
2325030000	Industrial Processes;Mining and Quarrying: SIC 14;Sand and Gravel;Total

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SCC	SCC Description
2801000000	Miscellaneous Area Sources;Agriculture Production - Crops;Agriculture - Crops;Total
2801000002	Miscellaneous Area Sources;Agriculture Production - Crops;Agriculture - Crops;Planting
2801000003	Miscellaneous Area Sources;Agriculture Production - Crops;Agriculture - Crops;Tilling
2801000005	Miscellaneous Area Sources;Agriculture Production - Crops;Agriculture - Crops;Harvesting
2801000008	Miscellaneous Area Sources;Agriculture Production - Crops;Agriculture - Crops;Transport
2805001000	Miscellaneous Area Sources;Agriculture Production - Livestock;Beef cattle - finishing operations on feedlots (drylots);Dust Kicked-up by Hooves (use 28-05-020, -001, -002, or -003 for Waste

The dust emissions in the modeling platform are not the same as the 2011NEIv2 emissions because the NEI paved and unpaved road dust emissions include a built-in precipitation reduction that is based on average meteorological data, which is at a coarser temporal and spatial resolution than the modeling platform meteorological adjustment. Due to this, in the platform the paved and unpaved road emissions, data used did not include any precipitation-based reduction. This allows the entire sector to be processed consistently so that the same grid-specific transport fractions and meteorological adjustments can be applied. Where states submitted afdust data, it was assumed that the state-submitted data were not met-adjusted and therefore the meteorological adjustments were still applied. Thus, it is possible that these sources may have been adjusted twice. Even with that possibility, air quality modeling shows that in general, dust is frequently overestimated in the air quality modeling results.

The total impacts of the transport fraction and meteorological adjustments for the 2011NEIv2 are shown in Table 2-7, where the starting inventory numbers include unadjusted paved and unpaved road dust, so they do not match the NEI values because those include a different type of adjustment. The amount of the reduction ranges from about 93% in New Hampshire to about 29% in Nevada.

Figure 2-1 shows the impact of each step of the adjustment for 2011. The reductions due to the transport fraction adjustments alone are shown at the top of Figure 2-1. The reductions due to the precipitation adjustments are shown in the middle of Figure 2-1. The cumulative emission reductions after both transport fraction and meteorological adjustments are shown at the bottom of Figure 2-1. The top plot shows how the transport fraction has a larger reduction effect in the east, where forested areas are more effective at reducing PM transport than in many western areas. The middle plot shows how the meteorological impacts of precipitation, along with snow cover in the north, further reduce the dust emissions.

Table 2-7. Total Impact of Fugitive Dust Adjustments to Unadjusted 2011 Inventory

State	Unadjusted PM10	Unadjusted PM2_5	Change in PM10	Change in PM2_5	PM10 Reduction	PM2_5 Reduction
Alabama	378,874	47,158	-310,750	-38,597	82%	82%
Arizona	237,361	30,015	-78,519	-9,778	33%	33%
Arkansas	421,958	58,648	-305,611	-40,757	72%	69%
California	255,889	38,664	-119,035	-17,930	47%	46%
Colorado	244,630	40,421	-130,598	-20,991	53%	52%

State	Unadjusted PM10	Unadjusted PM2_5	Change in PM10	Change in PM2_5	PM10 Reduction	PM2_5 Reduction
Connecticut	29,067	4,393	-25,877	-3,912	89%	89%
Delaware	11,548	1,968	-8,219	-1,396	71%	71%
D.C.	2,115	337	-1,596	-254	75%	75%
Florida	292,797	39,637	-181,017	-24,333	62%	61%
Georgia	733,478	90,041	-593,644	-72,028	81%	80%
Idaho	432,116	49,294	-291,880	-32,897	68%	67%
Illinois	763,665	123,680	-472,806	-76,086	62%	62%
Indiana	603,152	85,151	-435,027	-60,660	72%	72%
Iowa	590,528	96,070	-339,349	-54,855	57%	57%
Kansas	747,242	118,726	-352,559	-54,760	47%	46%
Kentucky	199,744	29,496	-160,640	-23,511	80%	80%
Louisiana	236,787	35,730	-162,780	-24,086	69%	67%
Maine	50,547	7,016	-43,643	-6,078	86%	87%
Maryland	65,701	10,215	-49,481	-7,691	75%	75%
Massachusetts	205,561	22,444	-177,808	-19,370	86%	86%
Michigan	462,324	61,969	-353,225	-47,137	76%	76%
Minnesota	336,791	64,253	-217,036	-41,145	64%	64%
Mississippi	956,702	107,965	-782,249	-86,685	82%	80%
Missouri	1,063,992	130,995	-780,488	-94,576	73%	72%
Montana	385,541	50,583	-266,046	-33,521	69%	66%
Nebraska	591,457	85,206	-316,918	-45,198	54%	53%
Nevada	160,699	20,477	-47,147	-5,688	29%	28%
New Hampshire	25,540	3,766	-23,836	-3,515	93%	93%
New Jersey	24,273	5,412	-19,215	-4,255	79%	79%
New Mexico	924,497	95,871	-352,117	-36,344	38%	38%
New York	274,114	37,493	-236,431	-31,990	86%	85%
North Carolina	186,650	33,409	-146,918	-26,184	79%	78%
North Dakota	354,107	59,113	-218,630	-36,286	62%	61%
Ohio	414,902	64,609	-319,831	-49,298	77%	76%
Oklahoma	733,750	87,864	-385,344	-44,585	53%	51%
Oregon	348,093	40,596	-268,605	-30,516	77%	75%
Pennsylvania	208,246	30,344	-179,991	-26,158	86%	86%
Rhode Island	4,765	731	-3,628	-564	76%	77%
South Carolina	259,350	31,494	-198,175	-24,002	76%	76%
South Dakota	262,935	44,587	-155,938	-26,215	59%	59%
Tennessee	139,731	25,357	-107,964	-19,514	77%	77%
Texas	2,573,687	304,551	-1,278,053	-146,122	50%	48%

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State	Unadjusted PM10	Unadjusted PM2_5	Change in PM10	Change in PM2_5	PM10 Reduction	PM2_5 Reduction
Utah	196,551	21,589	-113,837	-12,464	58%	58%
Vermont	67,690	7,563	-61,423	-6,855	91%	91%
Virginia	131,798	19,374	-108,700	-15,895	82%	82%
Washington	174,969	27,999	-99,720	-15,425	57%	55%
West Virginia	85,956	10,652	-79,745	-9,888	93%	93%
Wisconsin	239,851	41,669	-164,113	-28,542	68%	68%
Wyoming	434,090	45,350	-264,580	-27,467	61%	61%
Domain Total	**18,525,814**	**2,489,943**	**-11,790,743**	**-1,566,004**	**64%**	**63%**

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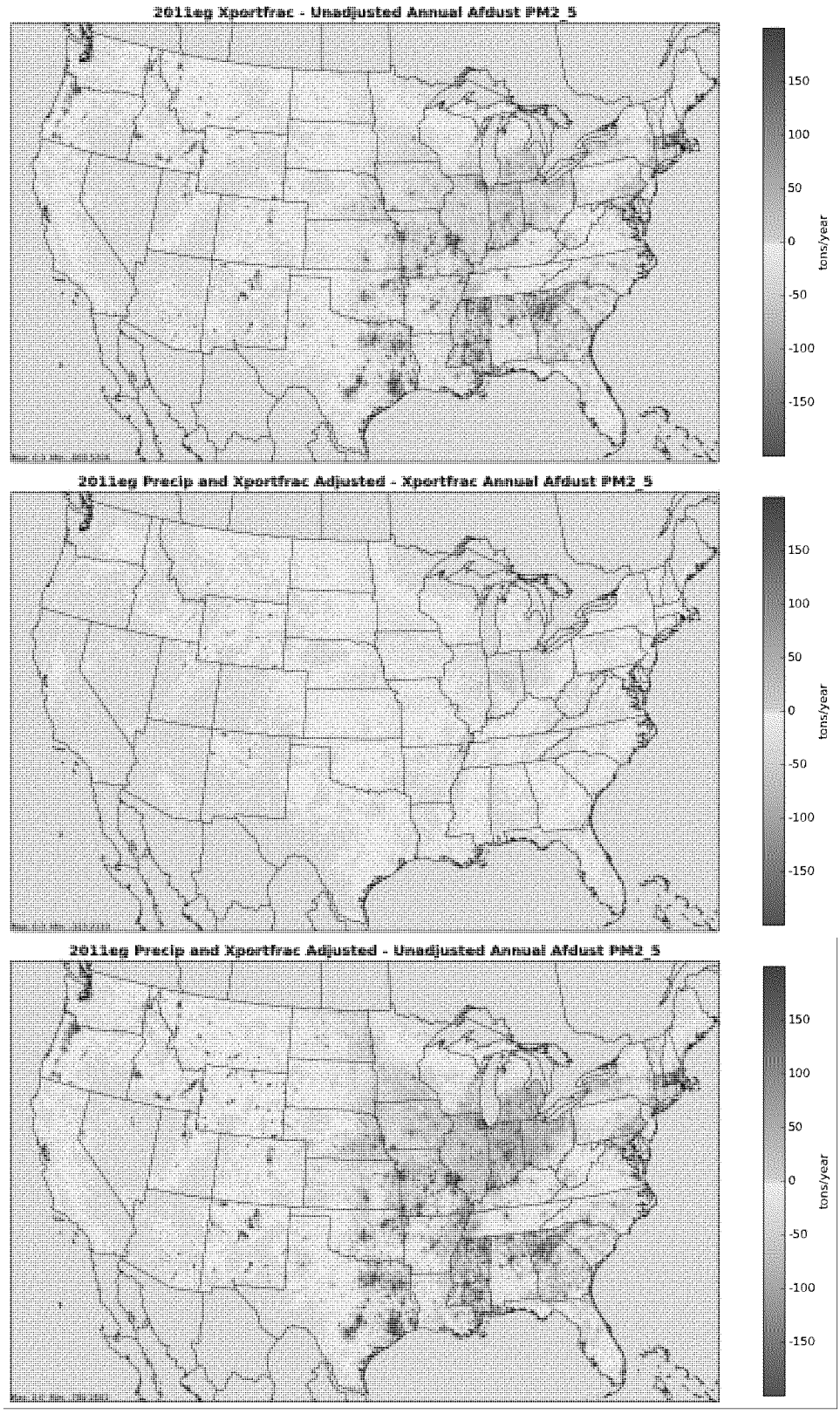
Figure 2-1. Impact of adjustments to fugitive dust emissions due to transport fraction, precipitation, and cumulative



2.2.2 Agricultural ammonia sector (ag)

The agricultural NH_3 (ag) sector includes livestock and agricultural fertilizer application emissions from the 2011NEIv2 nonpoint inventory. The livestock and fertilizer emissions in this sector are based only on the SCCs listed in Table 2-8 and Table 2-9. The "ag" sector includes all of the NH_3 emissions from fertilizer from the NEI. However, the "ag" sector does not include all of the livestock NH_3 emissions, as there are also a small amount of NH_3 emissions from livestock feedlots in the ptnonipm inventory (as point sources) in California (175 tons) and Wisconsin (125 tons).

Table 2-8. Livestock SCCs extracted from the NEI to create the ag sector

SCC	SCC Description*
2805001100	Beef cattle - finishing operations on feedlots (drylots);Confinement
2805001200	Beef cattle - finishing operations on feedlots (drylots);Manure handling and storage
2805001300	Beef cattle - finishing operations on feedlots (drylots);Land application of manure
2805002000	Beef cattle production composite; Not Elsewhere Classified
2805003100	Beef cattle - finishing operations on pasture/range; Confinement
2805007100	Poultry production - layers with dry manure management systems;Confinement
2805007300	Poultry production - layers with dry manure management systems;Land application of manure
2805008100	Poultry production - layers with wet manure management systems;Confinement
2805008200	Poultry production - layers with wet manure management systems;Manure handling and storage
2805008300	Poultry production - layers with wet manure management systems;Land application of manure
2805009100	Poultry production - broilers;Confinement
2805009200	Poultry production - broilers;Manure handling and storage
2805009300	Poultry production - broilers;Land application of manure
2805010100	Poultry production - turkeys;Confinement
2805010200	Poultry production - turkeys;Manure handling and storage
2805010300	Poultry production - turkeys;Land application of manure
2805018000	Dairy cattle composite;Not Elsewhere Classified
2805019100	Dairy cattle - flush dairy;Confinement
2805019200	Dairy cattle - flush dairy;Manure handling and storage
2805019300	Dairy cattle - flush dairy;Land application of manure
2805020000	Cattle and Calves Waste Emissions;Milk Total
2805020002	Cattle and Calves Waste Emissions:Beef Cows
2805021100	Dairy cattle - scrape dairy;Confinement
2805021200	Dairy cattle - scrape dairy;Manure handling and storage
2805021300	Dairy cattle - scrape dairy;Land application of manure
2805022100	Dairy cattle - deep pit dairy;Confinement
2805022200	Dairy cattle - deep pit dairy;Manure handling and storage
2805022300	Dairy cattle - deep pit dairy;Land application of manure
2805023100	Dairy cattle - drylot/pasture dairy;Confinement
2805023200	Dairy cattle - drylot/pasture dairy;Manure handling and storage
2805023300	Dairy cattle - drylot/pasture dairy;Land application of manure
2805025000	Swine production composite;Not Elsewhere Classified (see also 28-05-039, -047, -053)
2805030000	Poultry Waste Emissions;Not Elsewhere Classified (see also 28-05-007, -008, -009)
2805030003	Poultry Waste Emissions;Layers
2805030004	Poultry Waste Emissions;Broilers
2805030007	Poultry Waste Emissions;Ducks
2805030008	Poultry Waste Emissions;Geese
2805030009	Poultry Waste Emissions;Turkeys

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SCC	SCC Description*
2805035000	Horses and Ponies Waste Emissions;Not Elsewhere Classified
2805039100	Swine production - operations with lagoons (unspecified animal age);Confinement
2805039200	Swine production - operations with lagoons (unspecified animal age);Manure handling and storage
2805039300	Swine production - operations with lagoons (unspecified animal age);Land application of manure
2805040000	Sheep and Lambs Waste Emissions;Total
2805045000	Goats Waste Emissions;Not Elsewhere Classified
2805045002	Goats Waste Emissions;Angora Goats
2805045003	Goats Waste Emissions;Milk Goats
2805047100	Swine production - deep-pit house operations (unspecified animal age);Confinement
2805047300	Swine production - deep-pit house operations (unspecified animal age);Land application of manure
2805053100	Swine production - outdoor operations (unspecified animal age);Confinement

* All SCC Descriptions begin "Miscellaneous Area Sources;Agriculture Production – Livestock"

Table 2-9. Fertilizer SCCs extracted from the NEI for inclusion in the "ag" sector

SCC	SCC Description*
2801700001	Anhydrous Ammonia
2801700002	Aqueous Ammonia
2801700003	Nitrogen Solutions
2801700004	Urea
2801700005	Ammonium Nitrate
2801700006	Ammonium Sulfate
2801700007	Ammonium Thiosulfate
2801700008	Other Straight Nitrate
2801700009	Ammonium Phosphates
2801700010	N-P-K (multi-grade nutrient fertilizers)
2801700011	Calcium Ammonium Nitrate
2801700012	Potassium Nitrate
2801700013	Diammonium Phosphate
2801700014	Monoammonium Phosphate
2801700015	Liquid Ammonium Polyphosphate
2801700099	Miscellaneous Fertilizers

* All descriptions include "Miscellaneous Area Sources; Agriculture Production – Crops; Fertilizer Application" as the beginning of the description.

2.2.3 Agricultural fires (agfire)

The agricultural fire (agfire) sector contains emissions from agricultural fires. These emissions were placed into the sector based on their SCC code. All SCCs starting with 28015 are included. The first three levels of descriptions for these SCCs are: 1) Fires - Agricultural Field Burning; Miscellaneous Area Sources; 2) Agriculture Production - Crops - as nonpoint; and 3) Agricultural Field Burning - whole field set on fire. The SCC 2801500000 does not specify the crop type or burn method, while the more specific SCCs specify field or orchard crops and, in some cases, the specific crop being grown. For more information on how emissions for agricultural fires were developed in the 2011NEIv2, see Section 5.2 of the 2011NEIv2 TSD.

2.2.4 Nonpoint source oil and gas sector (np_oilgas)

The nonpoint oil and gas (np_oilgas) sector contains onshore and offshore oil and gas emissions. The EPA estimated emissions for all counties with 2011 oil and gas activity data with the Oil and Gas Tool, and many S/L/T agencies also submitted nonpoint oil and gas data. The types of sources covered include drill rigs, workover rigs, artificial lift, hydraulic fracturing engines, pneumatic pumps and other devices, storage tanks, flares, truck loading, compressor engines, and dehydrators. Nonpoint oil and gas emissions for most states in the 2011v6.3 platform are consistent with those in the 2011NEIv2. For more information on the development of the oil and gas emissions in the 2011NEIv2, see Section 3.20 of the 2011NEIv2 TSD. The S/L/T agencies that submitted data used in 2011v6.3 include Texas, Oklahoma and Utah.

2.2.5 Residential wood combustion sector (rwc)

The residential wood combustion (rwc) sector includes residential wood burning devices such as fireplaces, fireplaces with inserts (inserts), free standing woodstoves, pellet stoves, outdoor hydronic heaters (also known as outdoor wood boilers), indoor furnaces, and outdoor burning in firepots and chimneas. Free standing woodstoves and inserts are further differentiated into three categories: 1) conventional (not EPA certified); 2) EPA certified, catalytic; and 3) EPA certified, noncatalytic. Generally speaking, the conventional units were constructed prior to 1988. Units constructed after 1988 had to meet EPA emission standards and they are either catalytic or non-catalytic. For more information on the development of the residential wood combustion emissions, see Section 3.14 of the 2011NEIv2 TSD. The SCCs in the rwc sector are shown in Table 2-10.

Table 2-10. SCCs in the Residential Wood Combustion Sector (rwc)*

SCC	SCC Description
2104008100	SSFC;Residential;Wood;Fireplace: general
2104008210	SSFC;Residential;Wood;Woodstove: fireplace inserts; non-EPA certified
2104008220	SSFC;Residential;Wood;Woodstove: fireplace inserts; EPA certified; non-catalytic
2104008230	SSFC;Residential;Wood;Woodstove: fireplace inserts; EPA certified; catalytic
2104008300	SSFC;Residential;Wood;Woodstove: freestanding, general
2104008310	SSFC;Residential;Wood;Woodstove: freestanding, non-EPA certified
2104008320	SSFC;Residential;Wood;Woodstove: freestanding, EPA certified, non-catalytic
2104008330	SSFC;Residential;Wood;Woodstove: freestanding, EPA certified, catalytic
2104008400	SSFC;Residential;Wood;Woodstove: pellet-fired, general (freestanding or FP insert)
2104008420	SSFC;Residential;Wood;Woodstove: pellet-fired, EPA certified (freestanding or FP insert)
2104008510	SSFC;Residential;Wood;Furnace: Indoor, cordwood-fired, non-EPA certified
2104008610	SSFC;Residential;Wood;Hydronic heater: outdoor
2104008700	SSFC;Residential;Wood;Outdoor wood burning device, NEC (fire-pits, chimeas, etc)
2104009000	SSFC;Residential;Firelog;Total: All Combustor Types

* SSFC=Stationary Source Fuel Combustion

2.2.6 Other nonpoint sources sector (nonpt)

Stationary nonpoint sources that were not subdivided into the afdust, ag, np_oilgas, or rwc sectors were assigned to the "nonpt" sector. Locomotives and CMV mobile sources from the 2011NEIv2 nonpoint inventory are described in Section 2.4.1. There are too many SCCs in the nonpt sector to list all of them individually, but the types of sources in the nonpt sector include:

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- stationary source fuel combustion, including industrial, commercial, and residential;
- chemical manufacturing;
- industrial processes such as commercial cooking, metal production, mineral processes, petroleum refining, wood products, fabricated metals, and refrigeration;
- solvent utilization for surface coatings such as architectural coatings, auto refinishing, traffic marking, textile production, furniture finishing, and coating of paper, plastic, metal, appliances, and motor vehicles;
- solvent utilization for degreasing of furniture, metals, auto repair, electronics, and manufacturing;
- solvent utilization for dry cleaning, graphic arts, plastics, industrial processes, personal care products, household products, adhesives and sealants;
- solvent utilization for asphalt application and roofing, and pesticide application;
- storage and transport of petroleum for uses such as portable gas cans, bulk terminals, gasoline service stations, aviation, and marine vessels;
- storage and transport of chemicals;
- waste disposal, treatment, and recovery via incineration, open burning, landfills, and composting;
- agricultural burning and orchard heating;
- miscellaneous area sources such as cremation, hospitals, lamp breakage, and automotive repair shops.

2.3 2011 onroad mobile sources (onroad)

Onroad mobile sources include emissions from motorized vehicles that are normally operated on public roadways. These include passenger cars, motorcycles, minivans, sport-utility vehicles, light-duty trucks, heavy-duty trucks, and buses. The sources are further divided between diesel, gasoline, E-85, and compressed natural gas (CNG) vehicles. The sector characterizes emissions from parked vehicle processes (e.g., starts, hot soak, and extended idle) as well as from on-network processes (i.e., from vehicles moving along the roads). Except for California and Texas, all onroad emissions are generated using the SMOKE-MOVES emissions modeling framework that leverages MOVES-generated outputs (https://www.epa.gov/moves) and hourly meteorological data. For more information on the preparation of onroad mobile source emissions with SMOKE-MOVES, see the 2011v6.3 platform TSD.

There were no changes to onroad emissions or how they were processed for 2011en as compared to 2011el. The primary change to the onroad mobile source sector that were made for the *2011el* case concerns the penetration of E-85 fuels. Specifically, the percentage of E-85 in the activity data used to compute the EPA-default emissions for the 2011el case was updated to reflect actual usage of E-85 fuel, instead of reflecting activity from all "flex-fuel" vehicles which *could* use E-85. In the 2011ek case, 5.14 percent of all passenger vehicle VMT activity was allocated to E-85. That percentage reflects all flex-fuel vehicles on the road, whether or not those vehicles are actually using E-85. In the 2011el case, only 0.016 percent of total passenger vehicle VMT was allocated to E-85 fuel, reflecting the actual amount of E-85 fuel consumed. Table 2-11 shows the total onroad U.S. CAP emissions in the 2011v6.3 and updated platforms, rounded to the nearest thousand tons. The slight increase in some pollutants is due to the fact the E-85 emission factors are somewhat cleaner than those of regular gasoline. Thus, with the percent of E-85 reduced, the emissions increase slightly.

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Table 2-11. Onroad CAP emissions in the 2011v6.3 and updated platforms (tons)

Pollutant	2011ek	2011el	% change
CO	25,380,000	25,992,000	2%
NH3	112,000	121,000	8%
NOX	5,609,000	5,708,000	2%
PM10	326,000	327,000	0%
PM2_5	188,000	189,000	1%
SO2	27,000	28,000	3%
VOC	2,657,000	2,713,000	2%

California onroad emissions were also updated for the *2023el* platform. The California onroad inventory includes updated vehicle type and road type distribution, so that they are estimated in a consistent way with the state-provided 2023 emissions. The vehicle type and road type distribution is based on the latest mapping between EMFAC Emissions Inventory Codes (EICs) and EPA source classification codes (SCCs), and unlike prior EIC-to-SCC mappings, distinguishes on-network emissions from off-network emissions.

For the continental U.S., EPA used a modeling framework that took into account the temperature sensitivity of the on-road emissions. Specifically, EPA used MOVES inputs for representative counties, vehicle miles traveled (VMT), vehicle population (VPOP), and hoteling data for all counties, along with tools that integrated the MOVES model with SMOKE. In this way, it was possible to take advantage of the gridded hourly temperature information available from meteorology modeling used for air quality modeling. The "SMOKE-MOVES" integration tool was developed by EPA in 2010 and is used for regional air quality modeling of onroad mobile sources.

SMOKE-MOVES requires that emission rate "lookup" tables be generated by MOVES which differentiate emissions by process (i.e., running, start, vapor venting, etc.), vehicle type, road type, temperature, speed, hour of day, etc. To generate the MOVES emission rates that could be applied across the U.S., EPA used an automated process to run MOVES to produce emission factors by temperature and speed for a series of "representative counties," to which every other county is mapped. Representative counties are used because it is impractical to generate a full suite of emission factors for the more than 3,000 counties in the United States. Representative counties, for which emission factors are generated are selected according to their state, elevation, fuels, age distribution, ramp fraction, and inspection & maintenance programs. Each county is then mapped to a representative county based on its similarity with the representative county with respect to those attributes. For the 2011v6.3 platform, there are 285 representative counties.

Once representative counties have been identified, emission factors are generated with MOVES for each representative county and for each "fuel month" – typically a summer month and a winter month. Using the MOVES emission rates, SMOKE selects appropriate emissions rates for each county, hourly temperature, SCC, and speed bin and multiplies the emission rate by activity: VMT (vehicle miles travelled), VPOP (vehicle population)), or HOTELING (hours of extended idle) to produce emissions. These calculations were done for every county and grid cell in the continental U.S. for each hour of the year.

The SMOKE-MOVES process for creating the model-ready emissions consists of the following steps:

1) Determine which counties will be used to represent other counties in the MOVES runs.

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2) Determine which months will be used to represent other month's fuel characteristics.
3) Create MOVES inputs needed only by MOVES. MOVES requires county-specific information on vehicle populations, age distributions, and inspection-maintenance programs for each of the representative counties.
4) Create inputs needed both by MOVES and by SMOKE, including temperatures and activity data.
5) Run MOVES to create emission factor tables for the temperatures found in each county.
6) Run SMOKE to apply the emission factors to activity data (VMT, VPOP, and HOTELING) to calculate emissions based on the gridded hourly temperatures in the meteorological data.
7) Aggregate the results to the county-SCC level for summaries and quality assurance.

The onroad emissions are processed in four processing streams that are merged together into the onroad sector emissions after processing:

- rate-per-distance (RPD) uses VMT as the activity data plus speed and speed profile information to compute on-network emissions from exhaust, evaporative, permeation, refueling, and brake and tire wear processes;
- rate-per-vehicle (RPV) uses vehicle population (VPOP) activity data to compute off-network emissions from exhaust, evaporative, permeation, and refueling processes;
- rate-per-profile (RPP) uses VPOP activity data to compute off-network emissions from evaporative fuel vaper venting including hot soak (immediately after a trip) and diurnal (vehicle parked for a long period) emissions; and
- rate-per-hour (RPH) uses hoteling hours activity data to compute off-network emissions for idling of long-haul trucks from extended idling and auxiliary power unit process.

The onroad emissions inputs are similar to the emissions in the onroad data category of the 2011NEIv2, described in more detail in Section 4.6 of the 2011NEIv2 TSD. Specifically, the 2011v6.3 platform and the 2011NEIv2 have nearly identical:

- MOVES County databases (CDBs) including Low Emission Vehicle table dated 20140903
- Representative counties (i.e., 285RepCos2011_M2014_20151208)
- Fuel months
- Meteorology
- Activity data (VMT, VPOP, speed, HOTELING)

SMOKE-MOVES are both run using a detailed set of processes, but in the NEI emissions were aggregated into two modes: refueling and all other modes. In addition, the NEI SCCs were aggregated over roads to all parking and all road emissions. The list of modes (or aggregate processes) used in the v6.2 platform and the corresponding MOVES processes mapped to them are listed in Table 2-12.

Table 2-12. Onroad emission aggregate processes

Aggregate process	Description	MOVES process IDs
40	All brake and tire wear	9;10
53	All extended idle exhaust	17;90
62	All refueling	18;19
72	All exhaust and evaporative except refueling and hoteling	1;2;11;12;13;15;16
91	Auxiliary Power Units	91

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One reason that brake and tire wear was split out from the other processes was to allow for better modeling of the impacts of electric vehicles in future years, since these vehicles still have brake and tire wear emissions, but do not have exhaust, evaporative, or refueling emissions. For more detailed information on methods used to develop the onroad emissions and input data sets and on running SMOKE-MOVES, see the 2011NEIv2 TSD.

The California and Texas onroad emissions were created through a hybrid approach of combining state-supplied annual emissions with EPA-developed SMOKE-MOVES runs. Through this approach, the platform was able to reflect the unique rules in California and Texas, while leveraging the more detailed SCCs and the highly resolved spatial patterns, temporal patterns, and speciation from SMOKE-MOVES. The basic steps involved in temporally allocating onroad emissions from California and Texas based on SMOKE-MOVES results were:

1) Run CA and TX using EPA inputs through SMOKE-MOVES to produce hourly 2011 emissions hereafter known as "EPA estimates." These EPA estimates for CA and TX are run in a separate sector called "onroad_catx."
2) Calculate ratios between state-supplied emissions and EPA estimates[2]. For California, these were calculated for each county/SCC/pollutant combination, except with all road types summed together because California's emissions did not provide data by road type, and with E-85 emissions combined with gasoline because separate emissions were not provided for E-85. For Texas, the ratios were calculated for each county/SCC/pollutant combination, including by road type, but also with E-85 combined with gasoline.
3) Create an adjustment factor file (CFPRO) that includes EPA-to-state estimate ratios.
4) Rerun CA and TX through SMOKE-MOVES using EPA inputs and the new adjustment factor file.

Through this process, adjusted model-ready files were created that sum to annual totals from California and Texas, but have the temporal and spatial patterns reflecting the highly resolved meteorology and SMOKE-MOVES. After adjusting the emissions, this sector is called "onroad_catx_adj." Note that in emission summaries, the emissions from the "onroad" and "onroad_catx_adj" sectors are summed and designated as the emissions for the onroad sector.

An additional step was taken for the refueling emissions. Colorado submitted point emissions for gasoline refueling for some counties[3]. For these counties, the EPA zeroed out the onroad estimates of gasoline refueling (SCC 2201*62) so that the states' point emissions would take precedence. The onroad refueling emissions were zeroed out using the adjustment factor file (CFPRO) and Movesmrg.

[2] These ratios were created for all matching pollutants. These ratios were duplicated for all appropriate modeling species. For example, EPA used the NO_X ratio for NO, NO_2, HONO and used the $PM_{2.5}$ ratio for PEC, PNO_3, POC, PSO_4, etc. (For more details on NO_X and PM speciation, see Sections 3.2.2, and 3.2.3. For VOC model-species, if there was an exact match (e.g., BENZENE), the EPA used that HAP pollutant ratio. For other VOC-based model-species that didn't exist in the NEI inventory, the EPA used VOC ratios.

[3] There were 53 counties in Colorado that had point emissions for gasoline refueling. Outside Colorado, it was determined that refueling emissions in the 2011 NEIv2 point did not significantly overlap the refueling emissions in onroad.

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2.4 2011 nonroad mobile sources (cmv_c1c2, cmv_c3, rail, nonroad)

The nonroad mobile source emission modeling sectors consist of nonroad equipment emissions (nonroad), locomotive (rail) and CMV emissions.

2.4.1 Category 1, Category 2, Category 3 Commercial Marine Vessels (cmv_c1c2, cmv_c3)

In the 2011el case, the cmv sector contained all Category 1, 2 and 3 CMV emissions in U.S. waters. In the 2011en case, the CMV emissions are split between the cmv_c1c2 and the cmv_c3 sectors but the total emissions are essentially unchanged. In the NEI emissions in these sectors are annual and at the county-SCC resolution and based on the 2011NEIv2. The NEI CMV emissions use state-submitted values and EPA-developed emissions in areas where states did not submit. The emissions include the offshore portion of the C1 and C2 commercial marine sources, including fishing vessels and oil rig support vessels in the Gulf of Mexico. Emissions that occur outside of state waters are not assigned to states. For more information on CMV sources in the NEI, see Section 4.3 of the 2011NEIv2 TSD.

Table 2-13. 2011NEIv2 SCCs extracted for the cmv sector

SCC	Sector	Description: Mobile Sources prefix for all
2280002100	cmv	Marine Vessels; Commercial; Diesel; Port
2280002200	cmv	Marine Vessels; Commercial; Diesel; Underway
2280003100	cmv	Marine Vessels, Commercial;Residual;Port emissions
2280003200	cmv	Marine Vessels, Commercial;Residual;Underway emissions
2280004000	cmv	Marine Vessels, Commercial;Gasoline;Total, All Vessel Types

In 2011el, the cmv sector was updated to incorporate updated CMV emissions in California so that they are estimated in a consistent way with the state-provided 2023 emissions. A comparison of the 2011NEIv2 and the updated emissions for California is shown in Table 2-14. In 2011en, these updated emissions are found in the cmv_c1c2 sector because in California, the ships are required to use cleaner diesel fuel in state waters instead of the residual fuel assumed for C3 ships in most areas.

Table 2-14. California CMV CAP emissions in the original and updated 2011v6.3 platforms (tons)

Pollutant	2011ek	2011el
CO	6,572	5,082
NH3	8	6
NOX	21,622	21,055
PM10	495	808
PM2_5	462	752
SO2	255	1,827
VOC	1,675	1,375

Category 3 (C3) CMV sources run on residual oil, are consistent with those in the 2011NEIv2, and use the SCCs 2280003100 and 2280003200 for port and underway emissions, respectively. In 2011en, the Category 3 (C3) CMV emissions were reallocated from area to point sources so that emissions could be assigned to layers higher than layer 1, but the emissions totals are the same as those in 2011el. The point sources in the cmv_c3 inventory align with the point sources in the Emissions Control Area (ECA) inventory (EPA, 2015b). A set of fixed stack parameters were assigned to every CMV point source

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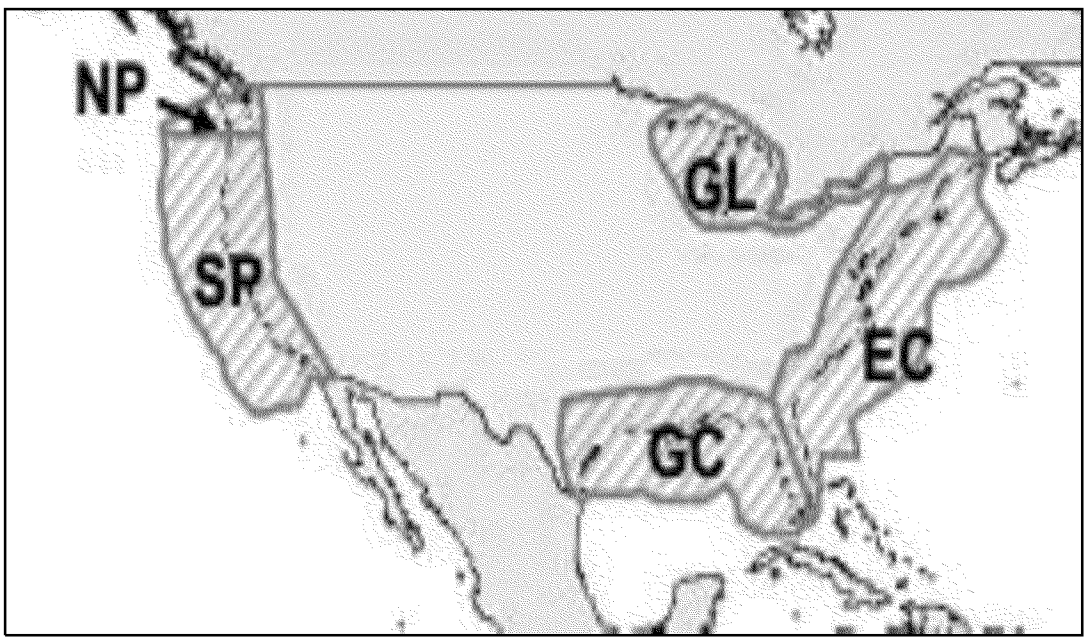
created in this process: stack height of 20 m, stack diameter of 0.8 m, stack velocity of 25 m/s, and a stack temperature of 282°C.

The base-year ECA inventory is 2002 and consists of these CAPs: PM_{10}, $PM_{2.5}$, CO, CO_2, NH_3, NO_X, SO_X (assumed to be SO_2), and hydrocarbons (assumed to be VOC). The EPA developed regional growth (activity-based) factors that were applied to create the 2011 inventory from the 2002 data. These growth factors are provided in Table 2-15. The geographic regions listed in the table are shown in Figure 2-2. * The East Coast and Gulf Coast regions were divided along a line roughly through Key Largo (longitude 80° 26' West). Technically, the Exclusive Economic Zone (EEZ) FIPS are not really "FIPS" state-county codes, but are treated as such in the inventory and emissions processing.

Table 2-15. Growth factors to project the 2002 ECA-IMO inventory to 2011

Region	**EEZ FIPS**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**VOC**	**CO**	**SO_2**
East Coast (EC)	85004	1.301	0.500	0.496	1.501	1.501	0.536
Gulf Coast (GC)	85003	1.114	0.428	0.423	1.288	1.288	0.461
North Pacific (NP)	85001	1.183	0.467	0.458	1.353	1.353	0.524
South Pacific (SP)	85002	1.367	0.525	0.521	1.565	1.562	0.611
Great Lakes (GL)	n/a	1.072	0.394	0.390	1.177	1.176	0.415
Outside ECA	98001	1.341	1.457	1.457	1.457	1.457	1.457

Figure 2-2. Illustration of regional modeling domains in ECA-IMO study



The emissions were converted to SMOKE point source inventory format allowing for the emissions to be allocated to modeling layers above the surface layer. As described in the paper, the ASCII raster dataset was converted to latitude-longitude, mapped to state/county FIPS codes that extended up to 200 nautical miles (nm) from the coast, assigned stack parameters, and monthly ASCII raster dataset emissions were used to create monthly temporal profiles. All non-US, non-EEZ emissions (i.e., in waters considered outside of the 200 nm EEZ and, hence, out of the U.S. and Canadian ECA-IMO

controllable domain) were simply assigned a dummy state/county FIPS code=98001, and were projected to year 2011 using the "Outside ECA" factors in Table 2-15.

The assignment of U.S. state/county FIPS codes was restricted to state-federal water boundaries data from the Mineral Management Service (MMS) that extend approximately 3 to 10 nm off shore. Emissions outside the 3 to 10 mile MMS boundary, but within the approximately 200 nm EEZ boundaries in Figure 2-2, were projected to year 2011 using the same regional adjustment factors as the U.S. emissions; however, the state/county FIPS codes were assigned as "EEZ" codes and those emissions processed in the "othpt" sector (see Section 2.5.1). Note that state boundaries in the Great Lakes are an exception, extending through the middle of each lake such that all emissions in the Great Lakes are assigned to a U.S. county or Ontario. This holds true for Midwest states and other states such as Pennsylvania and New York. The classification of emissions to U.S. and Canadian FIPS codes is needed to avoid double-counting of C3 CMV U.S. emissions in the Great Lakes because, as discussed in the previous section, all CMV emissions in the Midwest RPO are processed in the "cmv" sector.

The SMOKE-ready data have been cropped from the original ECA-IMO entire northwestern quarter of the globe to cover only the large continental U.S. 36-km "36US1" air quality model domain, the largest domain used by EPA in recent years[4]. The original ECA-IMO inventory did not delineate between ports and underway emissions (or other C3 modes such as hoteling, maneuvering, reduced-speed zone, and idling). However, a U.S. ports spatial surrogate dataset was used to assign the ECA-IMO emissions to ports and underway SCCs 2280003100 and 2280003200, respectively.

To prepare the cmv_c3 inventory for 2011en, in cases where counties and SCCs overlap between the 2011NEIv2 cmv_c3 inventory and the 2011 ECA point inventory, county to point allocation fractions by county and SCC were derived from the 2011 ECA point inventory. The county allocation fractions were calculated by dividing the 2011 ECA annual $PM_{2.5}$ emissions for each point source within a county by the total 2011 ECA $PM_{2.5}$ emissions for that county. These fractions were then applied to the cmv_c3 area county level 2011NEIv2 inventory emissions by associated county and SCC to get cmv_c3 emissions by county, SCC, and point source in point FF10 inventory format. The locations of the ECA point sources were carried forward into the cmv_c3 point inventory for each source that was allocated to a 2011NEIv2 cmv_c3 county.

Where the cmv_c3 area county-level inventory had emissions in counties not contained in the 2011 ECA point inventory, fallback factors by source type, port and underway, were applied to spatially allocate the emissions. These fallback methods produce cmv_c3 point sources at a 12km resolution based on polygons or surrogates. The fallback port point allocations were calculated based on the 2014 NATA v1 port polygons. Port activity was estimated by county using the fraction of PM2_5 emissions (SCC 2280003100) assigned to each port within a county. To get a total emissions allocation fraction from county to a 12US2 (see Figure 3-1) grid cell centroid the county activity fraction was multiplied by the fraction of area that a 12US2 grid cell overlaps each county port shape. Surrogate 801 was used as a tertiary fallback when port polygons were not available for a county with cmv_c3 port emissions. The underway point fallbacks were calculated from surrogate 806. County emissions (SCC 2280003200) were assigned to 12US2 grid cell centroids based on the county to grid cell surrogate fractions in surrogate 806. The underway surrogate fallback methodology is comparable to the surrogate 801 fallback used for port emissions.

[4] The extent of the "36US1" domain is similar to the full geographic region shown in Figure 3-1. Note that this domain is not specifically used in this 2011 platform, although spatial surrogates that can be used with it are provided.

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2.4.2 Railroad sources: (rail)

The rail sector includes all locomotives except for railway maintenance locomotives. Railway maintenance emissions are included in the nonroad sector. The yard locomotives are included in the ptnonipm sector. For more information on locomotive sources in the NEI, see Section 4.4 of the 2011NEIv2 TSD.

Table 2-16. 2011NEIv2 SCCs extracted for the starting point in rail development

SCC	Sector	Description: Mobile Sources prefix for all
2285002007	rail	Railroad Equipment;Diesel;Line Haul Locomotives: Class II / III Operations
2285002008	rail	Railroad Equipment;Diesel;Line Haul Locomotives: Passenger Trains (Amtrak)
2285002009	rail	Railroad Equipment;Diesel;Line Haul Locomotives: Commuter Lines
2285002010	rail	Railroad Equipment;Diesel;Yard Locomotives

2.4.3 Nonroad mobile equipment sources: (nonroad)

The nonroad equipment emissions are equivalent to the emissions in the nonroad data category of the 2011NEIv2, with the exception that the modeling platform emissions also include monthly totals. All nonroad emissions are compiled at the county/SCC level. NMIM (EPA, 2005) creates the nonroad emissions on a month-specific basis that accounts for temperature, fuel types, and other variables that vary by month. The nonroad sector includes monthly exhaust, evaporative and refueling emissions from nonroad engines (not including commercial marine, aircraft, and locomotives) that EPA derived from NMIM for all states except California and Texas. Additional details on the development of the 2011NEIv2 nonroad emissions are available in Section 4.5 the 2011NEIv2 TSD.

California year 2011 nonroad emissions were submitted to the 2011NEIv2 and are also documented in a staff report (ARB, 2010a). The nonroad sector emissions in California were developed using a modular approach and include all rulemakings and updates in place by December 2010. These emissions were developed using Version 1 of the CEPAM, which supports various California off-road regulations such as in-use diesel retrofits (ARB, 2007), Diesel Risk-Reduction Plan (ARB, 2000) and 2007 State Implementation Plans (SIPs) for the South Coast and San Joaquin Valley air basins (ARB, 2010b).

The CARB-supplied nonroad annual inventory emissions values were converted to monthly values by using the aforementioned EPA NMIM monthly inventories to compute monthly ratios by county, SCC7 (fuel, engine type, and equipment type group), mode, and pollutant. The SCC7 ratios were used because the SCCs in the CARB inventory did not align with many of the SCCs in EPA NMIM inventory. By aggregating up to SCC7, the two inventories had a more consistent coverage of sources. Some VOC emissions were added to California to account for situations when VOC HAP emissions were included in the inventory, but there were no VOC emissions. These additional VOC emissions were computed by summing benzene, acetaldehyde, and formaldehyde for the specific sources.

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Texas year 2011 nonroad emissions were also submitted to the NEI. The 2011NEIv2 nonroad annual inventory emissions values were converted to monthly values by using EPA's NMIM monthly inventories to compute monthly ratios by county, SCC7, mode, and poll[5].

2.5 "Other Emissions": Emissions from Non-U.S. sources

The emissions from Canada, Mexico, and U.S. offshore drilling platforms are included as part of four emissions modeling sectors: othpt, othar, othafdust, and othon. The "oth" refers to the fact that these emissions are usually "other" than those that exist in areas that use the U.S. state-county geographic Federal Information Processing Standards (FIPS) for county locations, while the remaining characters provide the SMOKE source types: "pt" for point; "ar" for "area and nonroad mobile;" and "on" for onroad mobile. The changes in the 2011el case for emissions in the entire country of Mexico for each sector are shown in Table 2-17 and Table 2-18 shows the changes for Canada. The reasons for the changes are explained in the sub-sections that follow.

Table 2-17. Mexico CAP emissions in the 2011v6.3 and updated platforms (tons)

	CO	NH3	NOX	PM10	PM2_5	SO2	VOC
2011ek othpt	694,173	31,569	606,442	233,158	160,911	2,393,790	290,676
2011el othpt	683,482	32,773	651,521	241,496	168,144	2,276,770	303,905
2011ek othar	3,081,442	852,041	721,690	628,158	454,385	47,290	3,488,075
2011el othar	2,579,614	875,696	706,612	574,293	404,291	44,083	3,564,949
2011ek othon	23,220,743	53,309	1,650,448	16,582	12,002	25,449	2,159,346
2011el othon	5,887,937	9,170	1,411,830	57,782	43,576	22,470	541,390

Table 2-18. Canada CAP emissions in 2011el vs 2011en (tons)

Case and Sector	CO	NH3	NOx	PM10	PM2.5	SO2	VOC
2011el othafdust				6,018,802	938,015		
2011en othafdust				8,573,732	1,643,832		
2011el othar	4,151,170	468,863	667,282	244,765	199,352	156,765	1,285,976
2011en othar	3,265,982	509,752	768,873	301,445	259,832	86,284	1,243,806
2011el othon	4,262,403	24,226	506,407	23,572	18,019	2,381	262,908
2011en othon	2,259,190	8,884	505,059	29,840	22,772	1,673	205,535
2011el othpt	1,329,036	20,987	958,229	165,389	69,195	1,347,075	979,932
2011en othpt	1,405,817	19,240	833,998	133,709	57,660	1,235,619	963,504

2.5.1 Point Sources from Offshore C3 CMV, Drilling platforms, Canada and Mexico (othpt)

The othpt sectors includes offshore oil and gas drilling platforms that are beyond U.S. state-county boundaries in the Gulf of Mexico and point sources for Canada and Mexico. Point sources in Mexico were compiled based on the Inventario Nacional de Emisiones de Mexico, 2008 (ERG, 2014a). The 2011ek case used 2008 estimates, but in 2011el, the emissions were projected to the year 2011 by

[5] If there was no match at county/SCC7/mode/poll, the allocation would fall back to state/SCC7/mode/poll. If that did not find a match, then state/SCC7 was used. For a few situations, that would also fail to match and the monthly emissions were allocated with a similar SCC7.

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interpolating between 2008 emissions and projected 2014 emissions (ERG, 2016). The point source emissions in the 2008 inventory were converted to English units and into the FF10 format that could be read by SMOKE, missing stack parameters were gapfilled using SCC-based defaults, and latitude and longitude coordinates were verified and adjusted if they were not consistent with the reported municipality. Note that there are no explicit HAP emissions in this inventory.

The point source offshore oil and gas drilling platforms from the 2011NEIv2 were used. For Canadian point sources, 2013 emissions provided by Environment Canada were used. Temporal profiles and speciated emissions were also provided. Note that Canadian CMV emissions are in the othar sector and are not processed as point sources.

C3 CMV emissions assigned to either the Exclusive Economic Zone (EEZ) (defined as those emissions beyond the U.S. Federal waters approximately 3-10 miles offshore, and extending to about 200 nautical miles from the U.S. coastline) or to outlying waters beyond the EEZ, which were part of the othpt sector in the 2011el case, were moved to the *cmv_c3* sector for the 2011en case.

2.5.2 Area and Nonroad Mobile Sources from Canada and Mexico (othar, othafdust)

The othar sector includes nonpoint and nonroad mobile source emissions in Canada and Mexico. The Canadian sources were updated to month-specific year-2013 emissions provided by Environment Canada, including the Canadian C3 CMV emissions.

For the original 2011ek case, area and nonroad mobile sources in Mexico for 2008 were compiled the Inventario Nacional de Emisiones de Mexico, 2008 (ERG, 2014a). The 2008 emissions were quality assured for completeness, SCC assignments were made when needed, the pollutants expected for the various processes were reviewed, and adjustments were made to ensure that PM_{10} was greater than or equal to $PM_{2.5}$. The resulting inventory was written using English units to the nonpoint FF10 format that could be read by SMOKE and projected to the year 2014 (ERG, 2016). For the 2011el case, the area and nonroad emissions were linearly interpolated to represent the year 2011. Also in 2011el, wildfire and agricultural fire emissions were removed from the Mexico nonpoint inventory to prevent double counting emissions with the new ptfire_mxca sector. Note that unlike the U.S. inventories, there are no explicit HAPs in the nonpoint or nonroad inventories for Canada and Mexico and, therefore, all HAPs are created from speciation. For the 2011en case, an updated population surrogate was added to spatially allocate Mexican area and nonroad sources in the 2023en case.

The othafdust sector includes nonpoint fugitive dust source emissions for Canada only. For 2011en, Environment Canada provided an updated year 2013 inventory for the othafdust sector for this updated modeling platform. The othafdust inventory consisted of an annual inventory at the province resolution that was adjusted using export fraction and precipitation data to generate hourly, gridded emissions for this sector.

2.5.3 Onroad Mobile Sources from Canada and Mexico (othon)

The othon sector includes onroad mobile source emissions in Canada and Mexico. The Canadian sources were updated in the 2023en case using month-specific year-2013 emissions provided by Environment Canada. Note that unlike the U.S. inventories, there are no explicit HAPs in the onroad inventories for Canada and therefore all HAPs are created from speciation.

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For the 2011en case, an updated population surrogate was used to spatially allocate onroad sources in Mexico. For the earlier 2011el case, the onroad mobile sources in Mexico were updated to 2011 levels based on a run of MOVES-Mexico for 2011. The development of the 2011 onroad inventory for Mexico is described in Development of Mexico Emission Inventories for the 2014 Modeling Platform (ERG, 2016). The following information on how the 2011 onroad inventory was developed is from that document which also includes a comparison of the updated emissions with other recent inventories or onroad mobile sources in Mexico:

> "Under the sponsorship of USAID, through the Mexico Low Emissions Development Program (MLED), in early 2016 ERG adapted MOVES2014a (https://www.epa.gov/moves) to Mexico (USAID, 2016). As with the U.S. version of the model, "MOVES-Mexico" has the capability to produce comprehensive national vehicle emission inventories, and to provide a framework for users to create detailed regional emission inventories and microscale emission assessments. The approach for adapting MOVES was determined based on Mexico's available vehicle fleet and activity data, and to account for significant differences in vehicle emissions standards between Mexico and the U.S. To aid this, the Mexican government agency National Institute of Ecology and Climate Change (*Instituto Nacional de Ecología y Cambio Climático* or INECC) provided data for fundamental model inputs such as vehicle kilometers travelled, vehicle population, age distribution, and emission standards. INECC also provided data on over 250,000 roadside remote sensing device (RSD) measurements across 24 Mexican cities, which were analyzed to help calibrate MOVES-Mexico emission rates. The data from INECC and other government sources have been synthesized to create a national Mexico-specific MOVES database that can be used directly with MOVES2014a as an alternate default database, replacing the U.S. default database that comes with the U.S. model download. MOVES-Mexico can estimate vehicle emissions for calendar years 1990 through 2050 at the nation, state or municipio (county-equivalent) level."
>
> ...
>
> "[The 2011] on-road mobile source emissions inventory was developed using output from MOVES-Mexico. Emissions were generated for each municipio; for a typical weekday and typical weekend by month; for the pollutant set used for the U.S. NEI. Total annual emissions were compiled into a single Flat File 10 (FF10) format file. MOVES-Mexico was run in default mode, which reflects Mexico-specific data for key inputs such as vehicle population, VMT, fuels, inspection and maintenance (I/M) programs and Mexico's emission standards."
>
> ...
>
> "The outputs of the MOVES-Mexico runs were processed to obtain total annual emissions by pollutant and EPA Source Classification Code (SCC) and compiled into a single FF10 format file. This involved looping through the output databases for all the individual municipios; extracting the emissions for a particular pollutant from both the evaporative and non-evaporative output databases; and summing the emissions across all hours to obtain total emissions by day type (weekend and weekday) for each month. The total monthly emissions were then calculated as the product of the daily weekend (weekday) emissions and the number of weekends (weekdays) in each month. The monthly emissions were then summed to obtain annual emissions and converted to U.S. short tons."

2.6 U.S. Fires (ptfire)

In the 2011v6.3 platform, both the wildfires and prescribed burning emissions are contained in the ptfire sector. Fire emissions are specified at geographic coordinates (point locations) and have daily emissions values. The ptfire sectors exclude agricultural burning and other open burning sources that are included in the nonpt sector. Emissions are day-specific and include satellite-derived latitude/longitude of the

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fire's origin and other parameters associated with the emissions such as acres burned and fuel load, which allow estimation of plume rise. Emissions for the SCCs listed in Table 2-21 are treated as point sources and are consistent with the fires stored in the Events data category of the 2011NEIv2. For more information on the development of the 2011NEIv2 fire inventory, see Section 5.1 of the 2011NEIv2 TSD.

Table 2-19. 2011 Platform SCCs representing emissions in the ptfire modeling sectors

SCC	SCC Description*
2810001000	Other Combustion; Forest Wildfires; Total
2810001001	Other Combustion; Forest Wildfires; Wildland fire use
2811015000	Other Combustion-as Event; Prescribed Burning for Forest Management; Total

* The first tier level of the SCC Description is "Miscellaneous Area Sources"

The point source day-specific emission estimates for 2011 fires rely on SMARTFIRE 2 (Sullivan, et al., 2008), which uses the National Oceanic and Atmospheric Administration's (NOAA's) Hazard Mapping System (HMS) fire location information as input. Additional inputs include the CONSUMEv3.0 software and the Fuel Characteristic Classification System (FCCS) fuel-loading database to estimate fire emissions from wildfires and prescribed burns on a daily basis. The method involves the reconciliation of ICS-209 reports (Incident Status Summary Reports) with satellite-based fire detections to determine spatial and temporal information about the fires. A functional diagram of the SMARTFIRE 2 process of reconciling fires with ICS-209 reports is available in the documentation (Raffuse, et al., 2007). Once the fire reconciliation process is completed, the emissions are calculated using the U.S. Forest Service's CONSUMEv3.0 fuel consumption model and the FCCS fuel-loading database in the BlueSky Framework (Ottmar, et al., 2007).http://www.fs.fed.us/pnw/fera/research/smoke/consume/index.shtml

SMARTFIRE 2 estimates were used directly for all states except Georgia and Florida. For Georgia, the satellite-derived emissions were removed from the ptfire inventory and replaced with a separate state-supplied ptfire inventory. Adjustments were also made to Florida as described in Section 5.1.4 of the 2011NEIv2 TSD. These changes made the data in the ptfire inventory consistent with the data in the 2011NEIv2.

An update originally incorporated in the 2011v6.2 platform was to split fires over 20,000 acres into the respective grid cells that they overlapped. The idea of this was to prevent all emissions from going into a single grid cell when, in reality, the fire was more dispersed than a single point. The large fires were each projected as a circle over the area centered on the specified latitude and longitude, and then apportioned into the grid cells they overlapped. The area of each of the "subfires" was computed in proportion to the overlap with that grid cell. These "subfires" were given new names that were the same as the original, but with "_a", "_b", "_c", and "_d" appended as needed. The FIPS state and county codes and fire IDs for the fifteen fires apportioned to multiple grid cells are shown in Table 2-20.

Table 2-20. Large fires apportioned to multiple grid cells

County FIPS	Fire ID
32007	SF11C1774898
32007	SF11C1775252
32013	SF11C1774993
35027	SF11C1760072
35027	SF11C1760460

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County FIPS	Fire ID
46065	SF11C1503125
48003	SF11C1718109
48081	SF11C1742329
48125	SF11C1749358
48243	SF11C1738273
48243	SF11C1747162
48353	SF11C1759082
48371	SF11C1750272
48415	SF11C1742358
56013	SF11C1791126

2.7 Non-U.S. Fires (ptfire_mxca)

The development of the U.S. fires in the ptfire sector is described in the 2011v6.3 TSD (EPA, 2016a). The SCCs for this sector are listed in Table 2-21. In the 2011el case update to the 2011v6.3 platform, a new sector of fire emissions in Mexico and Canada was added. Note that unlike the other sectors, the ptfire_mxca sector emissions were processed with SMOKE 4.0 because it has better support for processing FF10-formatted fire inventories. Fire emissions are specified at geographic coordinates (point locations) and have daily emissions values. Emissions are day-specific and include satellite-derived latitude/longitude of the fire's origin and other parameters associated with the emissions such as acres burned and fuel load, which allow estimation of plume rise.

Table 2-21. 2011 Platform SCCs representing emissions in the ptfire modeling sectors

SCC	SCC Description*
2810001000	Other Combustion; Forest Wildfires; Total
2810001001	Other Combustion; Forest Wildfires; Wildland fire use
2811015000	Other Combustion-as Event; Prescribed Burning for Forest Management; Total

* The first tier level of the SCC Description is "Miscellaneous Area Sources."

The 2011 fire inventory for Canada was obtained from Environment Canada. This point source fire inventory was generated using the Canadian Wildland Fire Information System (CWFIS) (http://cwfis.cfs.nrcan.gc.ca). Area burned and daily fire spread estimates are derived from satellite products. CWFIS integrates multi-source data for national-level products. These data include a fuels database, fire weather, topography, moisture content, and fire type and duration information. CWFIS also uses the BlueSky module Fire Emission Production Simulator (FEPS) (Anderson, 2004) to generate day-specific SMOKE-ready emissions data. The CWFIS fire inventory can also include agricultural burns, however all CWFIS fires are labeled with SCC 2810001000. The output format from CWFIS currently only supports older versions of SMOKE. The CWFIS data were converted to SMOKE FF10 format for use in this modeling effort.

The Fire INventory from NCAR (FINN) (Wiedinmyer, 2011) version 1.5 was used to supply a fire inventory for Mexico. FINN (https://www2.acom.ucar.edu/modeling/finn-fire-inventory-ncar) provides daily, 1 km resolution, global estimates of the trace gas and particle emissions from open burning of biomass, which includes wildfire, agricultural fires, and prescribed burning and does not include biofuel

use and trash burning. This day-specific FINN data was downloaded from http://bai.acom.ucar.edu/Data/fire/ and was converted to SMOKE FF10 format for this modeling effort.

2.8 Biogenic emissions (beis)

Biogenic emissions were computed based on the same 11g version of the 2011 meteorology data used for the air quality modeling, and were developed using the Biogenic Emission Inventory System version 3.61 (BEIS3.61) within SMOKE. The landuse input into BEIS3.61 is the BELD version 4.1 which is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation based data from 2001 to 2014 from the FIA version 5.1. After the 2011el/2023el cases, additional quality assurance of the BELD4.1 resulted in minor corrections to the landuse data in three states including Washington, Texas and Florida. These minor corrections were implemented in the 2011en/2023en modeling cases and representing about less than 1% reduction in biogenic emissions in these three states. For more information on biogenic emissions, see the original 2011v6.3 platform TSD (EPA, 2016a).

BEIS3.61 has some important updates from BEIS 3.14. These include the incorporation of Version 4.1 of the Biogenic Emissions Land use Database (BELD4) for the 2011v6.3 platform, and the incorporation of a canopy model to estimate leaf-level temperatures (Pouliot and Bash, 2015). BEIS3.61 includes a two-layer canopy model. Layer structure varies with light intensity and solar zenith angle. Both layers of the canopy model include estimates of sunlit and shaded leaf area based on solar zenith angle and light intensity, direct and diffuse solar radiation, and leaf temperature (Bash et al., 2015). The new algorithm requires additional meteorological variables over previous versions of BEIS. The variables output from the Meteorology-Chemistry Interface Processor (MCIP) that are used to convert WRF outputs to CMAQ inputs are shown in Table 2-22.

Table 2-22. Meteorological variables required by BEIS 3.61

Variable	Description
LAI	leaf-area index
PRSFC	surface pressure
Q2	mixing ratio at 2 m
RC	convective precipitation per met TSTEP
RGRND	solar rad reaching sfc
RN	nonconvective precipitation per met TSTEP
RSTOMI	inverse of bulk stomatal resistance
SLYTP	soil texture type by USDA category
SOIM1	volumetric soil moisture in top cm
SOIT1	soil temperature in top cm
TEMPG	skin temperature at ground
USTAR	cell averaged friction velocity
RADYNI	inverse of aerodynamic resistance
TEMP2	temperature at 2 m

BELD version 4.1 is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation based data from 2001 to 2014 from the FIA version 5.1. Canopy coverage is based on the Landsat satellite National Land Cover Database (NLCD) product from 2011. The FIA includes approximately 250,000 representative plots of species fraction data that are within

approximately 75 km of one another in areas identified as forest by the NLCD canopy coverage. The 2011 NLCD provides land cover information with a native data grid spacing of 30 meters. For land areas outside the conterminous United States, 500 meter grid spacing land cover data from the Moderate Resolution Imaging Spectroradiometer (MODIS) is used.

Other improvements to the BELDv4.1 included the following:

- Used 30 meter NASA's Shuttle Radar Topography Mission (SRTM) elevation data (http://www2.jpl.nasa.gov/srtm/) which will more accurately define the elevation ranges of the vegetation species.
- Used the 2011 30 meter USDA Cropland Data Layer (CDL) data (http://www.nass.usda.gov/research/Cropland/Release/) to the BELD 4 agricultural categories.

To provide a sense of the scope and spatial distribution of the emissions, plots of annual BEIS outputs for isoprene and NO for 2011 are shown in Figure 2-3 and Figure 2-4, respectively.

2.9 SMOKE-ready non-anthropogenic inventories for chlorine

The ocean chlorine gas emission estimates are based on the build-up of molecular chlorine (Cl_2) concentrations in oceanic air masses (Bullock and Brehme, 2002). Data at 36 km and 12 km resolution were available and were not modified other than the model-species name "CHLORINE" was changed to "CL2" to support CMAQ modeling.

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Figure 2-3. Annual NO emissions output from BEIS 3.61 for 2011

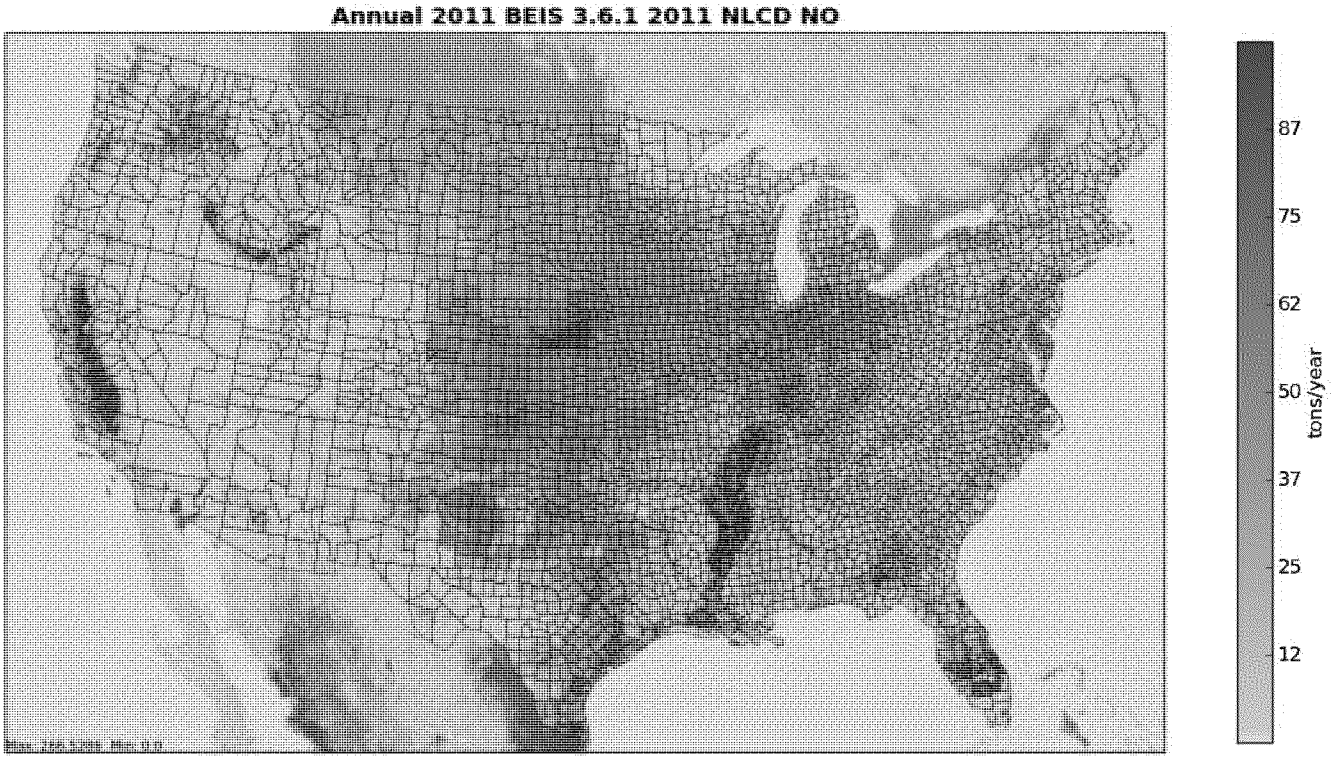
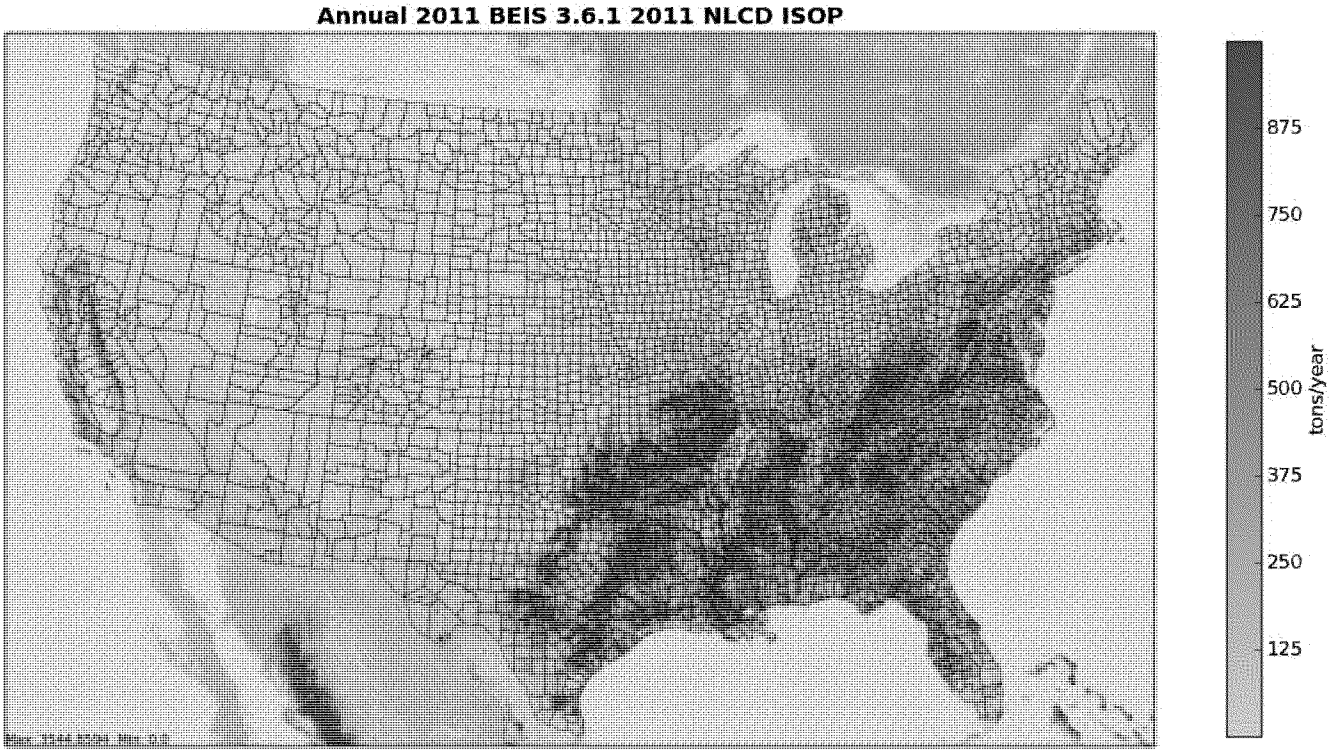


Figure 2-4. Annual isoprene emissions output from BEIS 3.61 for 2011



3 Emissions Modeling Summary

In Section 3, the descriptions of data are limited to updates to the ancillary data SMOKE uses to perform the emissions modeling steps. Note that all SMOKE inputs for this updated 2011v6.3 platform are available from the Air Emissions Modeling ftp site. While an overview of emissions modeling is given below, the details of the emissions modeling for the platform can be found in the original 2011v6.3 TSD (EPA, 2016a).

Both the CMAQ and CAMx models require hourly emissions of specific gas and particle species for the horizontal and vertical grid cells contained within the modeled region (i.e., modeling domain). To provide emissions in the form and format required by the model, it is necessary to "pre-process" the "raw" emissions (i.e., emissions input to SMOKE) for the sectors described above in Section 2. In brief, the process of emissions modeling transforms the emissions inventories from their original temporal resolution, pollutant resolution, and spatial resolution into the hourly, speciated, gridded resolution required by the air quality model. Emissions modeling includes temporal allocation, spatial allocation, and pollutant speciation. In some cases, emissions modeling also includes the vertical allocation of point sources, but many air quality models also perform this task because it greatly reduces the size of the input emissions files if the data are not provided for all vertical layers being modeled.

SMOKE version 3.7 was used to pre-process the raw emissions inventories into emissions inputs for each modeling sector in a format compatible with CMAQ. For projects that used CAMx, the CMAQ-formatted emissions were converted into the required CAMx formats using CAMx convertor programs. For sectors that have plume rise, the in-line emissions capability of the air quality models was used, which allows the creation of source-based and two-dimensional gridded emissions files that are much smaller than full three-dimensional gridded emissions files. For quality assurance of the emissions modeling steps, emissions totals for all species across the entire model domain are output as reports that are then compared to reports generated by SMOKE on the input inventories to ensure that mass is not lost or gained during the emissions modeling process.

The changes made to the ancillary emissions modeling files in the 2011en platform update are the following and are described in more detail in the subsections that follow:

- updates to speciation cross references for Canadian emissions;
- updates to temporal profiles for nonroad mobile source emissions;
- updates to temporal profiles used for U.S. EGUs;
- updates to temporal profiles for Canadian emissions;
- updates to plume rise treatment for U.S. C3 CMV sources;
- updates to spatial surrogates used in Canada, Mexico, and for U.S. CMV sources.

The changes made to the ancillary emissions modeling files in the 2011el platform update were the following and are described in more detail in the subsections that follow:

- updates related to the processing of MOVES-Mexico inventory data, including speciation, temporal, and gridding cross-references, speciation profiles, and inventory table;
- updates to the speciation cross reference to support fires in Canada and Mexico;
- development of speciation cross reference and GSPRO_COMBO files for 2023;

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- updates to monthly temporal profiles and the temporal cross reference for processing 2023 California nonroad emissions;
- development of MRCLIST files for 2023 onroad emission factors;
- development of CFPRO files for 2011 and 2023 onroad California and Texas adjustments; and
- updates to NHAPEXCLUDE files for some 2023 sectors.

3.1 Emissions Modeling Overview

When preparing emissions for the air quality model, emissions for each sector are processed separately through SMOKE, and then the final merge program (Mrggrid) is run to combine the model-ready, sector-specific emissions across sectors. The SMOKE settings in the run scripts and the data in the SMOKE ancillary files control the approaches used by the individual SMOKE programs for each sector. Table 3-1 summarizes the major processing steps of each platform sector. The "Spatial" column shows the spatial approach used: "point" indicates that SMOKE maps the source from a point location (i.e., latitude and longitude) to a grid cell; "surrogates" indicates that some or all of the sources use spatial surrogates to allocate county emissions to grid cells; and "area-to-point" indicates that some of the sources use the SMOKE area-to-point feature to grid the emissions (further described in Section 3.4.2). The "Speciation" column indicates that all sectors use the SMOKE speciation step, though biogenic speciation is done within the Tmpbeis3 program and not as a separate SMOKE step. The "Inventory resolution" column shows the inventory temporal resolution from which SMOKE needs to calculate hourly emissions. Note that for some sectors (e.g., onroad, beis), there is no input inventory; instead, activity data and emission factors are used in combination with meteorological data to compute hourly emissions.

Finally, the "plume rise" column indicates the sectors for which the "in-line" approach is used. These sectors are the only ones with emissions in aloft layers based on plume rise. The term "in-line" means that the plume rise calculations are done inside of the air quality model instead of being computed by SMOKE. The air quality model computes the plume rise using the stack data and the hourly air quality model inputs found in the SMOKE output files for each model-ready emissions sector. The height of the plume rise determines the model layer into which the emissions are placed. The othpt sector has only "in-line" emissions, meaning that all of the emissions are treated as elevated sources and there are no emissions for those sectors in the two-dimensional, layer-1 files created by SMOKE. Day-specific point fires are treated separately. For CMAQ modeling, fire plume rise is done within CMAQ itself, but for CAMx, the plume rise is done by running SMOKE to create a three-dimensional output file and then those emissions are postprocessed into a point source format that CAMx can read. In either case, after plume rise is applied, there will be emissions in every layer from the ground up to the top of the plume.

Table 3-1. Key emissions modeling steps by sector for 2011en

Platform sector	Spatial	Speciation	Inventory resolution	Plume rise
afdust	Surrogates	Yes	annual	
ag	Surrogates	Yes	annual	
agfire	Surrogates	Yes	monthly	
beis	Pre-gridded land use	in BEIS3.61	computed hourly	
rail	Surrogates	Yes	annual	
cmv_c1c2	Surrogates	Yes	annual	

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Platform sector	Spatial	Speciation	Inventory resolution	Plume rise
nonpt	Surrogates & area-to-point	Yes	annual	
nonroad	Surrogates & area-to-point	Yes	monthly	
np_oilgas	Surrogates	Yes	annual	
onroad	Surrogates	Yes	monthly activity, computed hourly	
othafdust	Surrogates	Yes	annual	
othar	Surrogates	Yes	annual & monthly	
othon	Surrogates	Yes	monthly	
othpt	Point	Yes	annual & monthly	in-line
cmv_c3	Point + surrogates	Yes	Annual	in-line
ptegu	Point	Yes	daily & hourly	in-line
ptfire	Point	Yes	daily	in-line
ptfire_mxca	Point	Yes	daily	in-line
ptnonipm	Point	Yes	annual	in-line
pt_oilgas	Point	Yes	annual	in-line
rwc	Surrogates	Yes	annual	

SMOKE has the option of grouping sources so that they are treated as a single stack when computing plume rise. For the 2011 platform, no grouping was performed because grouping combined with "in-line" processing will not give identical results as "offline" processing (i.e., when SMOKE creates three-dimensional files). This occurs when stacks with different stack parameters or latitudes/longitudes are grouped, thereby changing the parameters of one or more sources. The most straightforward way to get the same results between in-line and offline is to avoid the use of grouping.

To prepare fires for CAMx using a plume rise algorithm that is consistent with the algorithms in SMOKE and CMAQ, the following steps are performed:

1) The ptfire inventories are run through SMOKE programs to read the inventories, speciate, temporalize, and grid the emissions.

2) The SMOKE program laypoint is used to estimate the plume height and layer fractions for each fire (see https://www.cmascenter.org/smoke/documentation/3.7/html/ch06s06.html#sect_programs_laypoint_plume_rise_fires).

3) The emissions are gridded and layered, and then written as three-dimensional netCDF CMAQ ready files.

4) Species in the CMAQ-formatted file are converted to CAMx species using the *spcmap* program.

5) The netCDF **ptfire** files are converted to a CAMx "PTSOURCE" type file where each grid cell centroid represents one stack using the *cmaq2uam* program. Note that each virtual stack has default stack parameters of 1 m height, 1 m diameter, 273 K temperature, and 1 m/s

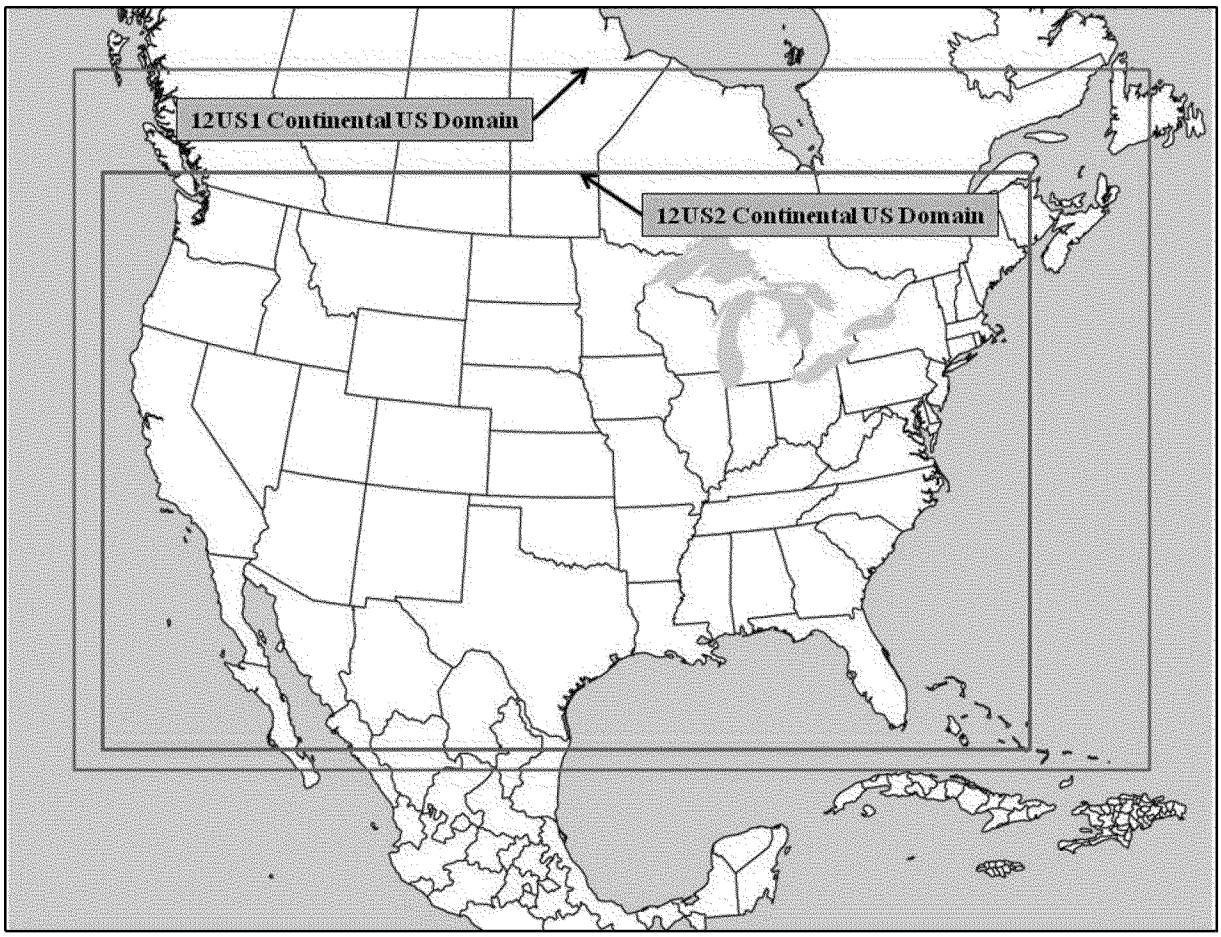
velocity. Also, an individual virtual stack point (grid cell centroid) will have all of the emissions for the grid cell divided up into layers with an effective plume height at each layer. Only the layers that contain emissions are kept for each virtual stack.

6) The program *pthtq* is run to add an effective plume height based on the cell center height from the METCRO3D (ZH).

7) The resulting PTSOURCE files have emissions as a stack at (x, y) that to up to layer z that is derived from the CMAQ 3D file, and are merged with the PTSOURCE sector files from other sectors into a single PTSOURCE file with stacks for all point sources. This file, along with the 2D emissions file, is input into the CAMx model.

SMOKE was run for the smaller 12-km CONtinental United States "CONUS" modeling domain (12US2) shown in Figure 3-1 and boundary conditions were obtained from a 2011 run of GEOS-Chem.

Figure 3-1. Air quality modeling domains



Both grids use a Lambert-Conformal projection, with Alpha = 33°, Beta = 45° and Gamma = -97°, with a center of X = -97° and Y = 40°. Table 3-2 describes the grids for the two domains.

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Table 3-2. Descriptions of the platform grids

Common Name	Grid Cell Size	Description (see Figure 3-1)	Grid name	Parameters listed in SMOKE grid description (GRIDDESC) file: projection name, xorig, yorig, xcell, ycell, ncols, nrows, nthik
Continental 12km grid	12 km	Entire conterminous US plus some of Mexico/Canada	12US1_459X299	'LAM_40N97W', -2556000, -1728000, 12.D3, 12.D3, 459, 299, 1
US 12 km or "smaller" CONUS-12	12 km	Smaller 12km CONUS plus some of Mexico/Canada	12US2	'LAM_40N97W', -2412000 , -1620000, 12.D3, 12.D3, 396, 246, 1

Section 3.4 provides the details on the spatial surrogates and area-to-point data used to accomplish spatial allocation with SMOKE.

3.2 Chemical Speciation

The emissions modeling step for chemical speciation creates the "model species" needed by the air quality model for a specific chemical mechanism. These model species are either individual chemical compounds (i.e., "explicit species") or groups of species (i.e., "lumped species"). The chemical mechanism used for the 2011 platform is the CB6 mechanism (Yarwood, 2010). The 2011v6.2 platform was the first EPA modeling platform to use CB6; previous platforms used CB05 and earlier versions of the carbon bond mechanism. The key difference in CB6 from CB05 from an emissions modeling perspective is that it has additional lumped and explicit model species. The specific version of CAMx used in applications of this platform include secondary organic aerosol (SOA) and nitrous acid (HONO) enhancements. In addition, this platform generates the $PM_{2.5}$ model species associated with the CMAQ Aerosol Module version 6 (AE6), though many are not used by CAMx. Table 3-3 of the 2011v6.3 platform TSD lists the model species produced by SMOKE in the 2011v6.2 platform Table 3-4 of the 2011v6.3 platform TSD (EPA, 2016a) provides the cmaq2camx mapping file used to convert the SMOKE generated model species to the appropriate inputs for CAMx.

The total organic gas (TOG) and $PM_{2.5}$ speciation factors that are the basis of the chemical speciation approach were developed from the SPECIATE 4.4 database https://www.epa.gov/air-emissions-modeling/speciate-version-45-through-40), which is the EPA's repository of TOG and PM speciation profiles of air pollution sources. However, a few of the profiles used in the v6.3 platform such as composite profiles for chemical manufacturing and pulp and paper sources will be published in later versions of the SPECIATE database after the release of this documentation. The SPECIATE database development and maintenance is a collaboration involving the EPA's Office of Research and Development (ORD), Office of Transportation and Air Quality (OTAQ), and the Office of Air Quality Planning and Standards (OAQPS), in cooperation with Environment Canada (EPA, 2006a). The SPECIATE database contains speciation profiles for TOG, speciated into individual chemical compounds, VOC-to-TOG conversion factors associated with the TOG profiles, and speciation profiles for $PM_{2.5}$.

Some special species are available in the emissions output from SMOKE: VOC_INV and NH3_FERT. The VOC_INV specie is carried through the modeling of each of the sectors so that emission summaries can be prepared for VOC without having to sum back up the individual VOC species which have different molecular weights. The VOC_INV is the total the amount of VOC in the input inventories and

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has units of g/s. The NH3_FERT is a specie that CMAQ uses for bidirectional ammonia modeling. It is set to the amount of ammonia from fertilizer sources. If the bidirectional option is turned off, the specie is ignored. It is also ignored for CAMx modeling.

Only minor changes were made to the speciation cross reference in 2011el update to the 2011v6.3 platform and there were no changes to U.S. speciation made for 2011en. Speciation for the updated 2011 emissions is the same as in the 2011 emissions from the 2011v6.3 platform, with the new ptfire_mxca sector emissions receiving the same speciation as the ptfire sector. Speciation for the 2023 emissions is the same as in the 2017 emissions from the 2011v6.3 platform, except for the VOC speciation COMBO profiles for bulk plant terminal-to-pump (BTP) emissions. COMBO profiles for 2023 were interpolated based on 2017 and 2025 COMBO profiles from the 2011v6.2 and 2011v6.3 emissions platforms.

The speciation cross reference and inventory table for the othon sector were configured so that VOC, $PM_{2.5}$ and NO_X are speciated in Canada only. In Mexico, pre-speciated VOC, $PM_{2.5}$, and NOx emissions from MOVES-Mexico are used. Some updates to speciation cross references in Canada were needed to accommodate new SCCs in the Canadian 2013 inventory.

Speciation profiles and cross-references for the 2011v6.3 platform are available in the SMOKE input files for the 2011v6.3 platform. Totals of each model species by state and sector can be found in the state-sector totals workbooks for the respective cases. In addition, the county-monthly reports for each case include EC and OC, and the 2011ek_county_SCC7_sector_CAP_PM.xlsx workbook contains speciated PM by county and the first seven digits of the SCC code.

Table 3-3. Emission model species produced for CB6 for CAM_X*

Inventory Pollutant	Model Species	Model species description
Cl_2	CL2	Atomic gas-phase chlorine
HCl	HCL	Hydrogen Chloride (hydrochloric acid) gas
CO	CO	Carbon monoxide
NO_X	NO	Nitrogen oxide
	NO2	Nitrogen dioxide
	HONO	Nitrous acid
SO_2	SO2	Sulfur dioxide
	SULF	Sulfuric acid vapor
NH_3	NH3	Ammonia
VOC	ACET	Acetone
	ALD2	Acetaldehyde
	ALDX	Propionaldehyde and higher aldehydes
	BENZ	Benzene
	CH4	Methane[6]
	ETH	Ethene
	ETHA	Ethane
	ETHY	Ethyne
	ETOH	Ethanol
	FORM	Formaldehyde
	KET	Ketone Groups

[6] Technically, CH_4 is not a VOC but part of TOG. Although emissions of CH_4 are derived, the AQ models do not use these emissions because the anthropogenic emissions are dwarfed by the CH_4 already in the atmosphere.

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Inventory Pollutant	Model Species	Model species description
	IOLE	Internal olefin carbon bond (R-C=C-R)
	ISOP	Isoprene
	MEOH	Methanol
	OLE	Terminal olefin carbon bond (R-C=C)
	PAR	Paraffin carbon bond
	PRPA	Propane
	TOL	Toluene and other monoalkyl aromatics
	XYL	Xylene and other polyalkyl aromatics
VOC species from the biogenics model that do not map to model species above	SESQ	Sesquiterpenes
	TERP	Terpenes
PM_{10}	PMC	Coarse PM > 2.5 microns and □ 10 microns
$PM_{2.5}$	PAL	Aluminum
	PCA	Calcium
	PCL	Chloride
	PEC	Particulate elemental carbon □ 2.5 microns
	PFE	Iron
	PK	Potassium
	PH2O	Water
	PMG	Magnesium
	PMN	Manganese
	PMOTHR	$PM_{2.5}$ not in other AE6 species
	PNA	Sodium
	PNCOM	Non-carbon organic matter
	PNO3	Particulate nitrate □ 2.5 microns
	PNH4	Ammonium
	POC	Particulate organic carbon (carbon only) □ 2.5 microns
	PSI	Silica
	PSO4	Particulate Sulfate □ 2.5 microns
	PTI	Titanium
Sea-salt species (non – anthropogenic)[7]	PCL	Particulate chloride
	PNA	Particulate sodium

*Notes:
1. CL2 is not used in CAM_X and is provided above because of its use in CMAQ
2. CAM_X particulate sodium is NA (in CMAQ it is PNA)
3. CAM_X uses different names for species that are both in CB6 and SOA for the following: TOLA=TOL, XYLA=XYL, ISP=ISOP, TRP=TERP. They are duplicate species in CAM_X that are used in the SOA chemistry. CMAQ uses the same names in CB05 and SOA for these species.
4. CAM_X uses a different name for sesquiterpenes: CMAQ SESQ = CAM_X SQT
5. CAM_X particulate species have different names for organic carbon, coarse particulate matter and other particulate mass: CAM_X uses POA, CPRM, FCRS, and FPRM, respectively.

[7] These emissions are created outside of SMOKE

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Table 3-4. Cmaq2camx mapping file

CMAQ Species	CMAQ to CAMx Factor	CAMx Species	Units	CMAQ Species	CMAQ to CAMx Factor	CAMx Species	Units
SO2	1	SO2	moles/hr	UNR	1	NR	moles/hr
SULF	1	SULF	moles/hr	NR	1	NR	moles/hr
NH3	1	NH3	moles/hr	TOL	1	TOLA	moles/hr
CO	1	CO	moles/hr	XYL	1	XYLA	moles/hr
NO	1	NO	moles/hr	PSO4	1	PSO4	g/hr
NO2	1	NO2	moles/hr	PH2O	1	PH2O	g/hr
HONO	1	HONO	moles/hr	PNH4	1	PNH4	g/hr
CL2	1	CL2	moles/hr	PNO3	1	PNO3	g/hr
HCL	1	HCL	moles/hr	PEC	1	PEC	g/hr
CH4	1	CH4	moles/hr	POC	1	POC	g/hr
PAR	1	PAR	moles/hr	PMOTHR	1	PMOTHR	g/hr
ETHA	1	ETHA	moles/hr	PMC	1	CPRM	g/hr
MEOH	1	MEOH	moles/hr	ISOP	1	ISP	moles/s
ETOH	1	ETOH	moles/hr	TERP	1	TRP	moles/s
ETH	1	ETH	moles/hr	SESQ	1	SQT	moles/s
OLE	1	OLE	moles/hr	PCL	1	PCL	g/hr
IOLE	1	IOLE	moles/hr	PNCOM	1	PNCOM	g/hr
ISOP	1	ISOP	moles/hr	PAL	1	PAL	g/hr
TERP	1	TERP	moles/hr	PCA	1	PCA	g/hr
FORM	1	FORM	moles/hr	PFE	1	PFE	g/hr
ALD2	1	ALD2	moles/hr	PMG	1	PMG	g/hr
ALDX	1	ALDX	moles/hr	PK	1	PK	g/hr
TOL	1	TOL	moles/hr	PMN	1	PMN	g/hr
XYL	1	XYL	moles/hr	PSI	1	PSI	g/hr
PRPA	1	PRPA	moles/hr	PTI	1	PTI	g/hr
ETHY	1	ETHY	moles/hr	PNA	1	NA	g/hr
BENZ	1	BENZ	moles/hr	POC	1	POA	g/hr
ACET	1	ACET	moles/hr	PNCOM	1	POA	g/hr
KET	1	KET	moles/hr				

3.2.1 VOC speciation

The concept of VOC speciation is to use emission source-related speciation profiles to convert VOC to TOG, to speciate TOG into individual chemical compounds, and to use a chemical mechanism mapping file to aggregate the chemical compounds to the chemical mechanism model species. The chemical mechanism mapping file is typically developed by the developer of the chemical mechanism.

SMOKE uses profiles that convert inventory species and TOG directly to the model species. The SMOKE-ready profiles are generated from the Speciation Tool which uses the "raw" (TOG to chemical compounds) SPECIATE profiles and the chemical mechanism mapping file.

For the 2011v6.3 platform, an updated CB6 chemical mapping file based on the August 2014 mechanism table for CB05 from Bill Carter was used for all sectors, including onroad mobile sources.

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This CB6 mapping file included some corrections to the onroad CB05 profiles used in the 2011v6.2 platform. Similarly to previous platforms, HAP VOC inventory species were used in the VOC speciation process for some sectors as described below.

3.2.1.1 The combination of HAP BAFM (benzene, acetaldehyde, formaldehyde and methanol) and VOC for VOC speciation

The VOC speciation includes HAP emissions from the 2011NEIv2 in the speciation process. Instead of speciating VOC to generate all of the species listed in Table 3-3, emissions of four specific HAPs: benzene, acetaldehyde, formaldehyde and methanol (collectively known as "BAFM") from the NEI were "integrated" with the NEI VOC. The integration combines these HAPs with the VOC in a way that does not double count emissions and uses the HAP inventory directly in the speciation process. The basic process is to subtract the specified HAPs emissions mass from the VOC emissions mass, and to then use a special "integrated" profile to speciate the remainder of VOC to the model species excluding the specific HAPs. The EPA believes that the HAP emissions in the NEI are often more representative of emissions than HAP emissions generated via VOC speciation, although this varies by sector.

The BAFM HAPs were chosen for integration in previous platforms because, with the exception of BENZENE[8], they are the only explicit VOC HAPs in the base version of the CMAQ 5.0.2 (CAPs only with chlorine chemistry) model. These remain appropriate for the 2011v6.3 platform since they are all explicit in CAMx. Explicit means that they are not lumped chemical groups like PAR, IOLE and several other CB6 model species. These "explicit VOC HAPs" are model species that participate in the modeled chemistry using the CB6 chemical mechanism. The use of inventory HAP emissions along with VOC is called "HAP-CAP integration."

For specific sources, especially within the nonpt sector, the integration included ethanol. To differentiate when a source was integrating BAFM versus EBAFM (ethanol in addition to BAFM), the speciation profiles that do not include ethanol are referred to as an "E-profile" and should be used when ethanol comes from the inventory. For example, the E10 headspace gasoline evaporative speciation profile 8763 should be used when ethanol is speciated from VOC, but 8763E should be used when ethanol is obtained directly from the inventory.

The integration of HAP VOC with VOC is a feature available in SMOKE for all inventory formats other than PTDAY (the format used for the ptfire sector). SMOKE allows the user to specify both the particular HAPs to integrate via the INVTABLE and the particular sources to integrate via the NHAPEXCLUDE file (which actually provides the sources to be *excluded* from integration[9]). For the "integrated" sources, SMOKE subtracts the "integrated" HAPs from the VOC (at the source level) to compute emissions for the new pollutant "NONHAPVOC." The user provides NONHAPVOC-to-NONHAPTOG factors and NONHAPTOG speciation profiles[10]. SMOKE computes NONHAPTOG and then applies the speciation profiles to allocate the NONHAPTOG to the other air quality model VOC species not including the integrated HAPs. After determining if a sector is to be integrated, if all sources have the appropriate HAP emissions, then the sector is considered fully integrated and does not

[8] BENZENE was chosen to keep its emissions consistent between the multi-pollutant and base versions of CMAQ.
[9] In SMOKE version 3.7, the options to specify sources for integration are expanded so that a user can specify the particular sources to include or exclude from integration, and there are settings to include or exclude all sources within a sector. In addition, the error checking is significantly stricter for integrated sources. If a source is supposed to be integrated, but it is missing BAFM or VOC, SMOKE will now raise an error.
[10] These ratios and profiles are typically generated from the Speciation Tool when it is run with integration of a specified list of pollutants, for example BAFM.

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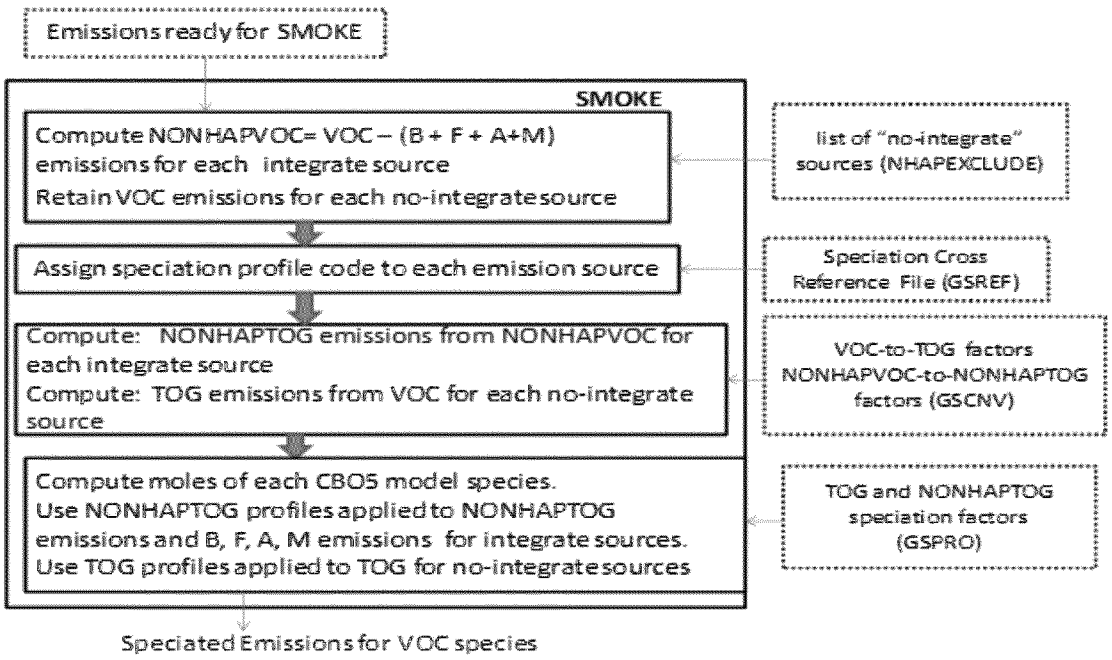
need a NHAPEXCLUDE file. If, on the other hand, certain sources do not have the necessary HAPs, then an NHAPEXCLUDE file must be provided based on the evaluation of each source's pollutant mix. The EPA considered CAP-HAP integration for all sectors and developed "integration criteria" for some of them (see Section 3.2.1.3 for details).

The process of partial integration for BAFM is illustrated in Figure 3-2 that the BAFM records in the input inventories do not need to be removed from any sources in a partially integrated sector because SMOKE does this automatically using the INVTABLE configuration. For EBAFM integration, this process is identical to that shown in the figure except for the addition of ethanol (E) to the list of subtracted HAP pollutants. For full integration, the process would be very similar except that the NHAPEXCLUDE file would not be used and all sources in the sector would be integrated.

Figure 3-2. Process of integrating BAFM with VOC for use in VOC Speciation



In SMOKE, the INVTABLE allows the user to specify both the particular HAPs to integrate. Two different types of INVTABLE files are included for use with different sectors of the platform. For sectors that had no integration across the entire sector (see Table 3-5), the EPA created a "no HAP use" INVTABLE in which the "KEEP" flag is set to "N" for BAFM pollutants. Thus, any BAFM pollutants in the inventory input into SMOKE are automatically dropped. This approach both avoids double-counting of these species and assumes that the VOC speciation is the best available approach for these species for sectors using this approach. The second INVTABLE, used for sectors in which one or more sources are integrated, causes SMOKE to keep the inventory BAFM pollutants and indicates that they are to be integrated with VOC. This is done by setting the "VOC or TOG component" field to "V" for all four HAP pollutants. This type of INVTABLE is further differentiated into a version for those sectors that integrate BAFM and another for those that integrate EBAFM.

Table 3-5. Integration approach for BAFM and EBAFM for each platform sector

Platform Sector	Approach for Integrating NEI emissions of Benzene (B), Acetaldehyde (A), Formaldehyde (F), Methanol (M), and Ethanol (E)
ptegu	No integration
ptnonipm	No integration
ptfire	No integration
othafdust	No integration
othar	No integration
othon	No integration
ag	N/A – sector contains no VOC
afdust	N/A – sector contains no VOC
biog	N/A – sector contains no inventory pollutant "VOC"; but rather specific VOC species
agfire	Partial integration (BAFM)
cmv	Partial integration (BAFM)
rail	Partial integration (BAFM)
nonpt	Partial integration (BAFM and EBAFM)
nonroad	Partial integration (BAFM)
np_oilgas	Partial integration (BAFM)
pt_oilgas	Partial integration (BAFM)
rwc	Partial integration (BAFM)
othpt	Partial integration (BAFM)
onroad	Full integration (internal to MOVES)[1]

[1]For the integration that is internal to MOVES, an extended list of HAPs are integrated, not just BAFM. See 3.2.1.3

More details on the integration of specific sectors and additional details of the speciation are provided in Section 3.2.1.3.

3.2.1.2 County specific profile combinations (GSPRO_COMBO)

SMOKE can compute speciation profiles from mixtures of other profiles in user-specified proportions. The combinations are specified in the GSPRO_COMBO ancillary file by pollutant (including pollutant mode, e.g., EXH__VOC), state and county (i.e., state/county FIPS code) and time period (i.e., month). This feature was used to speciate nonroad mobile and gasoline-related stationary sources that use fuels with varying ethanol content. In these cases, the speciation profiles require different combinations of gasoline profiles, e.g. E0 and E10 profiles. Since the ethanol content varies spatially (e.g., by state or county), temporally (e.g., by month), and by modeling year (future years have more ethanol), the GSPRO_COMBO feature allows combinations to be specified at various levels for different years. SMOKE computes the resultant profile using the fraction of each specific profile assigned by county, month and emission mode.

The GSREF file indicates that a specific source uses a combination file with the profile code "COMBO." Because the GSPRO_COMBO file does not differentiate by SCC and there are various levels of integration across sectors, sector-specific GSPRO_COMBO files are used. Different profile combinations are specified by the mode (e.g., exhaust, evaporative) and by changing the pollutant name (e.g., EXH__NONHAPTOG, EVP__NONHAPTOG). For the nonpt sector, a combination of BAFM and EBAFM integration is used. Due to the lack of SCC-specificity in the GSPRO_COMBO, the only way to differentiate the sources that should use BAFM integrated profiles versus E-profiles is by changing the pollutant name. For example, the EPA changed the pollutant name for the PFC future year

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inventory so the integration would use EVP__NONHAPVOC to correctly select the E-profile combinations, while other sources used NONHAPVOC to select the typical BAFM profiles.

3.2.1.3 Additional sector specific details

The decision to integrate HAPs into the speciation was made on a sector by sector basis. For some sectors, there is no integration and VOC is speciated directly; for some sectors, there is full integration meaning all sources are integrated; and for other sectors, there is partial integration, meaning some sources are not integrated and other sources are integrated. The integrated HAPs are either BAFM (BAFM HAPs subtracted from VOC) or EBAFM (ethanol and BAFM HAPs subtracted from VOC). Table 3-5 above summarizes the integration method for each platform sector.

For the cmv and rail sectors, the EPA integrated BAFM for most sources. There were a few sources that had zero BAFM and, therefore, they were not integrated. The CARB inventories (see Section 2.4.1) did not include HAPs and, therefore, all non-NEI source emissions in the cmv and rail sectors were not integrated. For California, the CARB inventory TOG was converted to VOC by dividing the inventory TOG by the available VOC-to-TOG speciation factor.

For the othpt sector, the C3 marine sources (see Section 2.4.2) are integrated. HAPs in this sector are derived identically to the U.S. C3 in the cmv sector. The rest of the sources in othpt are not integrated, thus the sector is partially integrated.

For the onroad sector, there are series of unique speciation issues. First, SMOKE-MOVES (see Section **Error! Reference source not found.**) is used to create emissions for these sectors and both the MEPROC and INVTABLE files are involved in controlling which pollutants are processed. Second, the speciation occurs within MOVES itself, not within SMOKE. The advantage of using MOVES to speciate VOC is that during the internal calculation of MOVES, the model has complete information on the characteristics of the fleet and fuels (e.g., model year, ethanol content, process, etc.), thereby allowing it to more accurately make use of specific speciation profiles. This means that MOVES produces EF tables that include inventory pollutants (e.g., TOG) and model-ready species (e.g., PAR, OLE, etc)[11]. SMOKE essentially calculates the model-ready species by using the appropriate emission factor without further speciation[12]. Third, MOVES' internal speciation uses full integration of an extended list of HAPs beyond EBAFM (called "M-profiles"). The M-profiles integration is very similar to BAFM integration explained above except that the integration calculation (see Figure 3-2) is performed on emissions factors instead of on emissions. The list of integrated HAPs is described in Table 3-6. An additional run of the speciation tool was necessary to create the M-profiles that were then loaded into the MOVES default database. Fourth, for California and Texas EPA applied adjustment factors to SMOKE-MOVES to produce California and Texas adjusted model-ready files (see Section **Error! Reference source not found.** for details). By applying the ratios through SMOKE-MOVES, the CARB and TCEQ inventories are essentially speciated to match EPA estimated speciation.

[11] Because the EF table has the speciation "baked" into the factors, all counties that are in the county group (i.e., are mapped to that representative county) will have the same speciation.
[12] For more details on the use of model-ready EF, see the SMOKE 3.7 documentation: https://www.cmascenter.org/smoke/documentation/3.7/html/.

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Table 3-6. MOVES integrated species in M-profiles

MOVES ID	Pollutant Name
5	Methane (CH4)
20	Benzene
21	Ethanol
22	MTBE
24	1,3-Butadiene
25	Formaldehyde
26	Acetaldehyde
27	Acrolein
40	2,2,4-Trimethylpentane
41	Ethyl Benzene
42	Hexane
43	Propionaldehyde
44	Styrene
45	Toluene
46	Xylene
185	Naphthalene gas

For the nonroad sector, CNG or LPG sources (SCCs beginning with 2268 or 2267) are not integrated because NMIM computed only VOC and not any HAPs for these SCCs. All other nonroad sources were integrated except in California. For California, the CARB inventory TOG was converted to VOC by dividing the inventory TOG by the available VOC-to-TOG speciation factor. SMOKE later applies the same VOC-to-TOG factor prior to computing speciated emissions. The CARB-based nonroad data includes exhaust and evaporative mode-specific data for VOC, but does not contain refueling. The CARB inventory does not include HAP estimates for all sources. Therefore, the sources which have VOC but not BAFM, or for which BAFM is greater than VOC, are not integrated and the remaining sources are integrated. The future year CARB inventories did not have BAFM so all sources for California were not integrated. The gasoline exhaust profiles were updated to 8750a and 8751a (this is true nation-wide).

Aircraft emissions use the profile 5565. In previous versions of the platform, a significant amount of VOC emissions associated with the pulp and paper and the chemical manufacturing industries did not have specific profiles assigned to them (i.e., they had the default VOC profile 0000). To address this, the EPA and Ramboll developed industry-wide average profiles to improve the speciation of these significant sources of VOC, since a large portion of the SCCs related to these industries used the default profile 00000. The two new composite profiles are "Composite Profile – Chemical Manufacturing (95325)" and "Composite Profile – Pulp and Paper Mills" (95326)[13].

For most sources in the rwc sector, the VOC emissions were greater than or equal to BAFM, and BAFM was not zero, so those sources were integrated, although a few specific sources that did not meet these criteria could not be integrated. For the oil and gas sources in the np_oilgas and pt_oilgas sectors, the basins studied in WRAP Phase III have basin-specific VOC speciation that takes into account the

[13] These profiles are expected to be included in SPECIATE 4.5.

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distinct composition of gas. ENVIRON developed these basin-specific profiles using gas composition analysis data obtained from operators through surveys. ENVIRON separated out emissions and speciation from conventional/tight sands/shale gas from coal-bed methane (CBM) gas sources. Table 3-7 lists the basin- and gas composition-specific profiles used for the sources in the WRAP Phase III basins. For oil and gas sources outside of the WRAP Phase III basins, the profiles did not vary by region or basin (see Table 3-8). Table 3-9 lists the WRAP Phase III counties.

Table 3-7. VOC profiles for WRAP Phase III basins

Profile Code	Description
DJFLA	D-J Basin Flashing Gas Composition for Condensate
DJVNT	D-J Basin Produced Gas Composition
PNC01	Piceance Basin Gas Composition at Conventional Wells
PNC02	Piceance Basin Gas Composition at Oil Wells
PNC03	Piceance Basin Flashing Gas Composition for Condensate
PRBCO	Powder River Basin Produced Gas Composition for Conventional Wells
PRM01	Permian Basin Produced Gas Composition
SSJCO	South San Juan Basin Produced Gas Composition for Conventional Wells
SWFLA	SW Wyoming Basin Flash Gas Composition
SWVNT	SW Wyoming Basin Vented Gas Composition
UNT02	Uinta Basin Gas Composition at Conventional Wells
UNT03	Uinta Basin Flashing Gas Composition for Oil
UNT04	Uinta Basin Flashing Gas Composition for Condensate
WRBCO	Wind River Basin Produced Gas Composition for Conventional Wells

Table 3-8. National VOC profiles for oil and gas

Profile	Description
0000	Over All Average
0001	External Combustion Boiler - Residual Oil
0002	External Combustion Boiler - Distillate Oil
0003	External Combustion Boiler - Natural Gas
0004	External Combustion Boiler - Refinery Gas
0007	Natural Gas Turbine
0008	Reciprocating Diesel Engine
0051	Flares - Natural Gas
0296	Fixed Roof Tank - Crude Oil Production
1001	Internal Combustion Engine - Natural Gas
1010	Oil and Gas Production - Fugitives - Unclassified
1011	Oil and Gas Production - Fugitives - Valves and Fittings - Liquid Service
1012	Oil and Gas Production - Fugitives - Valves and Fittings - Gas Service
1207	Well Heads (Water Flood) Composite
2487	Composite of 7 Emission Profiles from Crude Oil Storage Tanks - 1993
2489	Composite of 15 Fugitive Emission Profiles from Petroleum Storage Facilities - 1993
8489	Natural Gas Production
8950	Natural Gas Transmission

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Table 3-9. Counties included in the WRAP Dataset

FIPS	State	County
08001	CO	Adams
08005	CO	Arapahoe
08007	CO	Archuleta
08013	CO	Boulder
08014	CO	Broomfield
08029	CO	Delta
08031	CO	Denver
08039	CO	Elbert
08043	CO	Fremont
08045	CO	Garfield
08051	CO	Gunnison
08059	CO	Jefferson
08063	CO	Kit Carson
08067	CO	La Plata
08069	CO	Larimer
08073	CO	Lincoln
08075	CO	Logan
08077	CO	Mesa
08081	CO	Moffat
08087	CO	Morgan
08095	CO	Phillips
08097	CO	Pitkin
08103	CO	Rio Blanco
08107	CO	Routt
08115	CO	Sedgwick
08121	CO	Washington
08123	CO	Weld
08125	CO	Yuma
30003	MT	Big Horn
30075	MT	Powder River
35005	NM	Chaves
35015	NM	Eddy
35015	NM	Lea
35031	NM	Mc Kinley

FIPS	State	County
35039	NM	Rio Arriba
35041	NM	Roosevelt
35043	NM	Sandoval
35045	NM	San Juan
48003	TX	Andrews
48033	TX	Borden
48079	TX	Cochran
48081	TX	Coke
48103	TX	Crane
48105	TX	Crockett
48107	TX	Crosby
48109	TX	Culberson
48115	TX	Dawson
48125	TX	Dickens
48135	TX	Ector
48141	TX	El Paso
48151	TX	Fisher
48165	TX	Gaines
48169	TX	Garza
48173	TX	Glasscock
48219	TX	Hockley
48227	TX	Howard
48229	TX	Hudspeth
48235	TX	Irion
48263	TX	Kent
48269	TX	King
48301	TX	Loving
48303	TX	Lubbock
48305	TX	Lynn
48317	TX	Martin
48329	TX	Midland
48335	TX	Mitchell
48353	TX	Nolan
48371	TX	Pecos

FIPS	State	County
48383	TX	Reagan
48389	TX	Reeves
48413	TX	Schleicher
48415	TX	Scurry
48431	TX	Sterling
48435	TX	Sutton
48445	TX	Terry
48451	TX	Tom Green
48461	TX	Upton
48475	TX	Ward
48495	TX	Winkler
48501	TX	Yoakum
49007	UT	Carbon
49009	UT	Daggett
49013	UT	Duchesne
49015	UT	Emery
49019	UT	Grand
49043	UT	Summit
49047	UT	Uintah
56001	WY	Albany
56005	WY	Campbell
56007	WY	Carbon
56009	WY	Converse
56011	WY	Crook
56013	WY	Fremont
56019	WY	Johnson
56023	WY	Lincoln
56025	WY	Natrona
56027	WY	Niobrara
56033	WY	Sheridan
56035	WY	Sublette
56037	WY	Sweetwater
56041	WY	Uinta
56045	WY	Weston

Everywhere in the WRAP region (Table 3-9), WRAP speciation was applied instead of applying BAFM integration. VOC-to-TOG factors for WRAP speciation profiles were also updated for the 2011v6.3 platform. For the biog sector, the speciation profiles used by BEIS are not included in SPECIATE. The 2011 platform uses BEIS3.61, which includes a new species (SESQ) that was mapped to the model species SESQT. The profile code associated with BEIS3.61 for use with CB05 is "B10C5," while the

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profile for use with CB6 is "B10C6." The main difference between the profiles is the explicit treatment of acetone emissions in B10C6.

For the nonpt sector, where VOC emissions were greater than or equal to BAFM and BAFM was not zero, the sources were integrated. For portable fuel containers (PFCs) and fuel distribution operations associated with the bulk-plant-to-pump (BTP) distribution, ethanol may be mixed into the fuels; therefore, county- and month-specific COMBO speciation was used (via the GSPRO_COMBO file). Refinery to bulk terminal (RBT) fuel distribution and bulk plant storage (BPS) speciation are considered upstream from the introduction of ethanol into the fuel; therefore a single profile is sufficient for these sources. No refined information on potential VOC speciation differences between cellulosic diesel and cellulosic ethanol sources was available; therefore cellulosic diesel and cellulosic ethanol sources used the same SCC (30125010: Industrial Chemical Manufacturing, Ethanol by Fermentation production) for VOC speciation as was used for corn ethanol plants. For the future year, PFC and the cellulosic sources were integrated EBAFM (i.e., used E-profiles) because ethanol was present in those inventories.

3.2.1.4 Future year speciation

The VOC speciation approach used for the future year case is customized to account for the impact of fuel changes. These changes affect the onroad, nonroad, and parts of the nonpt and ptnonipm sectors.

Speciation profiles for VOC in the nonroad sector account for the changes in ethanol content of fuels across years. A description of the actual fuel formulations for 2011 can be found in the 2011NEIv2 TSD, and for 2023, see Section 4.3. For 2011, the EPA used "COMBO" profiles to model combinations of profiles for E0 and E10 fuel use. For 2023, the EPA assumed E10 fuel use for all nonroad gasoline processes.

The speciation changes from fuels in the nonpt sector are for PFCs and fuel distribution operations associated with the BTP distribution. For these sources, ethanol may be mixed into the fuels, in which case speciation would change across years. The speciation changes from fuels in the ptnonipm sector include BTP distribution operations inventoried as point sources. RBT fuel distribution and BPS speciation does not change across the modeling cases because this is considered upstream from the introduction of ethanol into the fuel. For PFCs, ethanol was present in the future inventories and, therefore, EBAFM profiles were used to integrate ethanol in the future year speciation.

Table 3-10 summarizes the different profiles utilized for the fuel-related sources in each of the sectors for 2011 and the future year cases. This table indicates when "E-profiles" were used instead of BAFM integrated profiles. The term "COMBO" indicates that a combination of the profiles listed was used to speciate that subcategory using the GSPRO_COMBO file.

Table 3-10. Select VOC profiles 2011 vs 2023

Sector	Sub-category	2011		2023	
nonroad	gasoline exhaust	COMBO 8750a 8751a	 Pre-Tier 2 E0 exhaust Pre-Tier 2 E10 exhaust	8751a	Pre-Tier 2 E10 exhaust
nonroad	gasoline evap-orative	COMBO 8753 8754	 E0 evap E10 evap	8754	E10 evap

Sector	Sub-category	2011		2023	
nonroad	gasoline refueling	COMBO 8869 8870	 E0 Headspace E10 Headspace	8870	E10 Headspace
nonroad	diesel exhaust	8774	Pre-2007 MY HDD exhaust	8774	Pre-2007 MY HDD exhaust
nonroad	diesel evap-orative	4547	Diesel Headspace	4547	Diesel Headspace
nonroad	diesel refueling	4547	Diesel Headspace	4547	Diesel Headspace
nonpt/ ptnonipm	PFC	COMBO 8869 8870	 E0 Headspace E10 Headspace	8870E	E10 Headspace
nonpt/ ptnonipm	BTP	COMBO 8869 8870	 E0 Headspace E10 Headspace	COMBO 8870 8871 8934	 E10 Headspace E15 Headspace E85 Evap
nonpt/ ptnonipm	BPS/RBT	8869	E0 Headspace	8869	E0 Headspace

The speciation of onroad VOC occurs within MOVES. MOVES takes into account fuel type and properties, emission standards as they affect different vehicle types and model years, and specific emission processes. A description of the actual fuel formulations for 2011 can be found in the 2011NEIv2 TSD. For 2023, see Section 4.3. Table 3-11 describes all of the M-profiles available to MOVES depending on the model year range, MOVES process (processID), fuel sub-type (fuelSubTypeID), and regulatory class (regClassID). Table 3-12 to Table 3-14 describe the meaning of these MOVES codes. For a specific representative county and future year, there will be a different mix of these profiles. For example, for HD diesel exhaust, the emissions will use a combination of profiles 8774M and 8775M depending on the proportion of HD vehicles that are pre-2007 model years (MY) in that particular county. As that county is projected farther into the future, the proportion of pre-2007 MY vehicles will decrease. A second example, for gasoline exhaust (not including E-85), the emissions will use a combination of profiles 8756M, 8757M, 8758M, 8750aM, and 8751aM. Each representative county has a different mix of these key properties and therefore has a unique combination of the specific M-profiles.

Table 3-11. Onroad M-profiles

Profile	Profile Description	Model Years	ProcessID	FuelSubTypeID	RegClassID
1001M	CNG Exhaust	1940-2050	1,2,15,16	30	48
4547M	Diesel Headspace	1940-2050	11	20,21,22	0
4547M	Diesel Headspace	1940-2050	12,13,18,19	20,21,22	10,20,30,40,41, 42,46,47,48
8753M	E0 Evap	1940-2050	12,13,19	10	10,20,30,40,41,42, 46,47,48
8754M	E10 Evap	1940-2050	12,13,19	12,13,14	10,20,30,40,41, 42,46,47,48
8756M	Tier 2 E0 Exhaust	2001-2050	1,2,15,16	10	20,30
8757M	Tier 2 E10 Exhaust	2001-2050	1,2,15,16	12,13,14	20,30

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Profile	Profile Description	Model Years	ProcessID	FuelSubTypeID	RegClassID
8758M	Tier 2 E15 Exhaust	1940-2050	1,2,15,16	15,18	10,20,30,40,41, 42,46,47,48
8766M	E0 evap permeation	1940-2050	11	10	0
8769M	E10 evap permeation	1940-2050	11	12,13,14	0
8770M	E15 evap permeation	1940-2050	11	15,18	0
8774M	Pre-2007 MY HDD exhaust	1940-2006	1,2,15,16,17,90	20, 21, 22	40,41,42,46,47, 48
8774M	Pre-2007 MY HDD exhaust	1940-2050	91[14]	20, 21, 22	46,47
8774M	Pre-2007 MY HDD exhaust	1940-2006	1,2,15,16	20, 21, 22	20,30
8775M	2007+ MY HDD exhaust	2007-2050	1,2,15,16	20, 21, 22	20,30
8775M	2007+ MY HDD exhaust	2007-2050	1,2,15,16,17,90	20, 21, 22	40,41,42,46,47,48
8855M	Tier 2 E85 Exhaust	1940-2050	1,2,15,16	50, 51, 52	10,20,30,40,41, 42,46,47,48
8869M	E0 Headspace	1940-2050	18	10	10,20,30,40,41, 42,46,47,48
8870M	E10 Headspace	1940-2050	18	12,13,14	10,20,30,40,41, 42,46,47,48
8871M	E15 Headspace	1940-2050	18	15,18	10,20,30,40,41, 42,46,47,48
8872M	E15 Evap	1940-2050	12,13,19	15,18	10,20,30,40,41, 42,46,47,48
8934M	E85 Evap	1940-2050	11	50,51,52	0
8934M	E85 Evap	1940-2050	12,13,18,19	50,51,52	10,20,30,40,41, 42,46,47,48
8750aM	Pre-Tier 2 E0 exhaust	1940-2000	1,2,15,16	10	20,30
8750aM	Pre-Tier 2 E0 exhaust	1940-2050	1,2,15,16	10	10,40,41,42,46,47,48
8751aM	Pre-Tier 2 E10 exhaust	1940-2000	1,2,15,16	11,12,13,14	20,30
8751aM	Pre-Tier 2 E10 exhaust	1940-2050	1,2,15,16	11,12,13,14,15, 18[15]	10,40,41,42,46,47,48

Table 3-12. MOVES Process IDs

Process ID	Process Name
1	Running Exhaust
2	Start Exhaust
11	Evap Permeation
12	Evap Fuel Vapor Venting
13	Evap Fuel Leaks
15	Crankcase Running Exhaust
16	Crankcase Start Exhaust
17	Crankcase Extended Idle Exhaust
18	Refueling Displacement Vapor Loss

[14] 91 is the processed for APUs which are diesel engines not covered by the 2007 Heavey-Duty Rule, so the older technology applieds to all years.

[15] The profile assingments for pre-2001 gasoline vehicles fueled on E15/E20 fuels (subtypes 15 and 18) were corrected for MOVES2014a. This model year range, process, fuelsubtype regclass combinate is already assigned to profile 8758.

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Process ID	Process Name
19	Refueling Spillage Loss
20	Evap Tank Permeation
21	Evap Hose Permeation
22	Evap RecMar Neck Hose Permeation
23	Evap RecMar Supply/Ret Hose Permeation
24	Evap RecMar Vent Hose Permeation
30	Diurnal Fuel Vapor Venting
31	HotSoak Fuel Vapor Venting
32	RunningLoss Fuel Vapor Venting
40	Nonroad
90	Extended Idle Exhaust
91	Auxiliary Power Exhaust

Table 3-13. MOVES Fuel subtype IDs

Fuel Subtype ID	Fuel Subtype Descriptions
10	Conventional Gasoline
11	Reformulated Gasoline (RFG)
12	Gasohol (E10)
13	Gasohol (E8)
14	Gasohol (E5)
15	Gasohol (E15)
18	Ethanol (E20)
20	Conventional Diesel Fuel
21	Biodiesel (BD20)
22	Fischer-Tropsch Diesel (FTD100)
30	Compressed Natural Gas (CNG)
50	Ethanol
51	Ethanol (E85)
52	Ethanol (E70)

Table 3-14. MOVES Regclass IDs

Reg. Class ID	Regulatory Class Description
0	Doesn't Matter
10	Motorcycles
20	Light Duty Vehicles
30	Light Duty Trucks
40	Class 2b Trucks with 2 Axles and 4 Tires (8,500 lbs < GVWR <= 10,000 lbs)
41	Class 2b Trucks with 2 Axles and at least 6 Tires or Class 3 Trucks (8,500 lbs < GVWR <= 14,000 lbs)
42	Class 4 and 5 Trucks (14,000 lbs < GVWR <= 19,500 lbs)
46	Class 6 and 7 Trucks (19,500 lbs < GVWR <= 33,000 lbs)
47	Class 8a and 8b Trucks (GVWR > 33,000 lbs)
48	Urban Bus (see CFR Sec 86.091_2)

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3.2.2 PM speciation

In addition to VOC profiles, the SPECIATE database also contains the $PM_{2.5}$ speciated into both individual chemical compounds (e.g., zinc, potassium, manganese, lead), and into the "simplified" $PM_{2.5}$ components used in the air quality model. We speciated $PM_{2.5}$ into the AE6 species associated with CMAQ 5.0.1 and later versions. While provided in the platform, they are not used in CAM_X but rather converted to the $PM_{2.5}$ species based on the cmaq2camx file presented in Table 3-4.

Table 3-15 shows the mapping of AE5 and AE6 for historical reference. The majority of the 2011 platform PM profiles come from the 911XX series which include updated AE6 speciation[16]. The 2011en_cb6v2 and 2023en_cb6v2 state-sector totals workbooks include state totals of the PM emissions for each state for the sectors that include PM.

Table 3-15. PM model species: AE5 versus AE6

Species name	Species description	AE5	AE6
POC	organic carbon	Y	Y
PEC	elemental carbon	Y	Y
PSO4	Sulfate	Y	Y
PNO3	Nitrate	Y	Y
PMFINE	unspeciated $PM_{2.5}$	Y	N
PNH4	Ammonium	N	Y
PNCOM	non-carbon organic matter	N	Y
PFE	Iron	N	Y
PAL	Aluminum	N	Y
PSI	Silica	N	Y
PTI	Titanium	N	Y
PCA	Calcium	N	Y
PMG	Magnesium	N	Y
PK	potassium	N	Y
PMN	Manganese	N	Y
PNA	Sodium	N	Y
PCL	Chloride	N	Y
PH2O	Water	N	Y
PMOTHR	$PM_{2.5}$ not in other AE6 species	N	Y

For the onroad sector, for all processes except brake and tire wear, PM speciation occurs within MOVES itself, not within SMOKE (similar to the VOC speciation described above). The advantage of using MOVES to speciate PM is that during the internal calculation of MOVES, the model has complete information on the characteristics of the fleet and fuels (e.g., model year, sulfur content, process, etc.) to accurately match to specific profiles. This means that MOVES produces EF tables that include total PM

[16] The exceptions are 5674 (Marine Vessel – Marine Engine – Heavy Fuel Oil) used for cmv and 92018 (Draft Cigarette Smoke – Simplified) used in nonpt.

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(e.g., PM_{10} and $PM_{2.5}$) and speciated PM (e.g., PEC, PFE, etc). SMOKE essentially calculates the PM components by using the appropriate EF without further speciation[17]. For onroad brake and tire wear, the PM is speciated in the *moves2smk* postprocessor that prepares the emission factors for processing in SMOKE. The formulas for this are based on the standard speciation factors that would otherwise be used in SMOKE via the profiles 91134 for brake wear and 91150 for tire wear:

```
POC = 0.4715 * PM25TIRE + 0.107 * PM25BRAKE
PEC = 0.22 * PM25TIRE + 0.0261 * PM25BRAKE
PNO3 = 0.0015 * PM25TIRE + 0.0016 * PM25BRAKE
PSO4 = 0.0311 * PM25TIRE + 0.0334 * PM25BRAKE
PNH4 = 0.00019 * PM25TIRE + 0.00003 * PM25BRAKE
PNCOM = 0.1886 * PM25TIRE + 0.0428 * PM25BRAKE
```

For California and Texas onroad emissions, adjustment factors were applied to SMOKE-MOVES to produce California and Texas adjusted model-ready files (see Section **Error! Reference source not found.** for details). California did not supply speciated PM, therefore, the adjustment factors applied to PM2.5 were also applied to the speciated PM components. By applying the ratios through SMOKE-MOVES, the CARB inventories are essentially speciated to match EPA estimated speciation. Texas did supply speciated PM, but it was determined that Texas's PM speciation was very similar to the PM speciation from MOVES, so EPA-estimated speciation was preserved in Texas as well as California.

3.2.3 NO_X speciation

NO_X can be speciated into NO, NO_2, and/or HONO. For the non-mobile sources, the EPA used a single profile "NHONO" to split NO_X into NO and NO_2. For the mobile sources, except for onroad (including nonroad, cmv, rail, othon sectors), and for specific SCCs in othar and ptnonipm, the profile "HONO" splits NO_X into NO, NO_2, and HONO. Table 3-16 gives the split factor for these two profiles. The onroad sector does not use the "HONO" profile to speciate NO_X. MOVES2014 produces speciated NO, NO_2, and HONO by source, including emission factors for these species in the emission factor tables used by SMOKE-MOVES. Within MOVES, the HONO fraction is a constant 0.008 of NO_X. The NO fraction varies by heavy duty versus light duty, fuel type, and model year. The NO_2 fraction = 1 – NO – HONO. For more details on the NO_X fractions within MOVES, see http://www.epa.gov/otaq/models/moves/documents/420r12022.pdf.

Table 3-16. NO_X speciation profiles

Profile	pollutant	species	split factor
HONO	NOX	NO2	0.092
HONO	NOX	NO	0.9
HONO	NOX	HONO	0.008
NHONO	NOX	NO2	0.1
NHONO	NOX	NO	0.9

[17] Unlike previous platforms, the PM components (e.g., POC) are now consistently defined between MOVES2014 and CMAQ. For more details on the use of model-ready EF, see the SMOKE 3.7 documentation: https://www.cmascenter.org/smoke/documentation/3.7/html/.

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3.3 Temporal Allocation

Temporal allocation (i.e., temporalization) is the process of distributing aggregated emissions to a finer temporal resolution, thereby converting annual emissions to hourly emissions. While the total emissions are important, the timing of the occurrence of emissions is also essential for accurately simulating ozone, PM, and other pollutant concentrations in the atmosphere. Many emissions inventories are annual or monthly in nature. Temporalization takes these aggregated emissions and, if needed, distributes them to the month, and then distributes the monthly emissions to the day and the daily emissions to the hours of each day. This process is typically done by applying temporal profiles to the inventories in this order: monthly, day of the week, and diurnal. A summary of emissions by temporal profile and sector for the 2011ek case is available from the reports area of the FTP site for the original 2011v6.3 platform ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/.

In SMOKE 3.7 and in the 2011v6.3 platform, more readable and flexible file formats are used for temporal profiles and cross references. The temporal factors applied to the inventory are selected using some combination of country, state, county, SCC, and pollutant. Table 3-17 summarizes the temporal aspects of emissions modeling by comparing the key approaches used for temporal processing across the sectors. In the table, "Daily temporal approach" refers to the temporal approach for getting daily emissions from the inventory using the SMOKE Temporal program. The values given are the values of the SMOKE L_TYPE setting. The "Merge processing approach" refers to the days used to represent other days in the month for the merge step. If this is not "all," then the SMOKE merge step runs only for representative days, which could include holidays as indicated by the right-most column. The values given are those used for the SMOKE M_TYPE setting (see below for more information).

Table 3-17. Temporal settings used for the platform sectors in SMOKE for 2011en

Platform sector short name	Inventory resolutions	Monthly profiles used?	Daily temporal approach	Merge processing approach	Process Holidays as separate days
afdust_adj	Annual	Yes	week	all	Yes
ag	Annual	Yes	all	all	Yes
agfire	Monthly		week	week	Yes
beis	Hourly		n/a	all	Yes
cmv_c1c2	Annual	Yes	aveday	aveday	
cmv_c3	Annual	Yes	aveday	aveday	
rail	Annual	Yes	aveday	aveday	
nonpt	Annual	Yes	week	week	Yes
nonroad	Monthly		mwdss	mwdss	Yes
np_oilgas	Annual	Yes	week	week	Yes
onroad	Annual & monthly[1]		all	all	Yes
onroad_ca_adj	Annual & monthly[1]		all	all	Yes
othafdust_adj	Annual	Yes	week	all	
othar	Annual & monthly	yes	week	week	
othon	Monthly		week	week	
othpt	Annual & monthly	yes	mwdss	mwdss	
pt_oilgas	Annual	yes	mwdss	mwdss	Yes

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Platform sector short name	Inventory resolutions	Monthly profiles used?	Daily temporal approach	Merge processing approach	Process Holidays as separate days
ptegu	Daily & hourly		all	all	Yes
ptnonipm	Annual	yes	mwdss	mwdss	Yes
ptfire	Daily		all	all	Yes
ptfire_mxca	Daily		all	all	Yes
rwc	Annual	no	met-based	all	Yes

[1] Note the annual and monthly "inventory" actually refers to the activity data (VMT and VPOP) for onroad. The actual emissions are computed on an hourly basis.

The following values are used in the table. The value "all" means that hourly emissions are computed for every day of the year and that emissions potentially have day-of-year variation. The value "week" means that hourly emissions computed for all days in one "representative" week, representing all weeks for each month. This means emissions have day-of-week variation, but not week-to-week variation within the month. The value "mwdss" means hourly emissions for one representative Monday, representative weekday (Tuesday through Friday), representative Saturday, and representative Sunday for each month. This means emissions have variation between Mondays, other weekdays, Saturdays and Sundays within the month, but not week-to-week variation within the month. The value "aveday" means hourly emissions computed for one representative day of each month, meaning emissions for all days within a month are the same. Special situations with respect to temporalization are described in the following subsections.

In addition to the resolution, temporal processing includes a ramp-up period for several days prior to January 1, 2011, which is intended to mitigate the effects of initial condition concentrations. The ramp-up period was 10 days (December 22-31, 2010). For most sectors, emissions from December 2011 were used to fill in surrogate emissions for the end of December 2010. In particular, December 2011 emissions (representative days) were used for December 2010. For biogenic emissions, December 2010 emissions were processed using 2010 meteorology.

3.3.1 Use of FF10 format for finer than annual emissions

The Flat File 2010 format (FF10) inventory format used by SMOKE provides a more consolidated format for monthly, daily, and hourly emissions inventories than prior formats supported. Previously, processing monthly inventory data required the use of 12 separate inventory files. With the FF10 format, a single inventory file can contain emissions for all 12 months and the annual emissions in a single record. This helps simplify the management of numerous inventories. Similarly, daily and hourly FF10 inventories contain individual records with data for all days in a month and all hours in a day, respectively.

SMOKE prevents the application of temporal profiles on top of the "native" resolution of the inventory. For example, a monthly inventory should not have annual-to-month temporalization applied to it; rather, it should only have month-to-day and diurnal temporalization. This becomes particularly important when specific sectors have a mix of annual, monthly, daily, and/or hourly inventories. The flags that control temporalization for a mixed set of inventories are discussed in the SMOKE documentation. The modeling platform sectors that make use of monthly values in the FF10 files are agfire, nonroad, onroad activity data, and ptegu.

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3.3.2 Nonroad temporalization (nonroad)

The only change to the temporal allocation process in the 2011el platform was the monthly temporalization of California nonroad emissions in 2023. In prior platforms, annual nonroad emissions in California were allocated to monthly values based on monthly distributions of the National Mobile Inventory Model (NMIM) emissions at the SCC7 level. This resulted in unrealistic monthly temporalization for some sub-SCC7 categories, for example, snowmobile emissions in the summer. A different set of monthly temporal profiles was applied to California nonroad emissions for 2023 with assignments based on full SCC, not SCC7, so that snowmobiles and other specific categories receive a more realistic monthly profile.

For the 2011en platform, temporal profile updates were implemented for nonroad emissions as shown in Figure 3-3 and Figure 3-4. Specifically, construction and commercial lawn and garden day-of-week profiles were updated from profile 18 to profile 19 while residential lawn and garden was unchanged from profile 9 and agriculture was unchanged from profile 18. Hour-of-day profiles for all four of these categories were updated from profile 26 to the following new assignments: construction now uses profile 26a, commercial lawn and garden uses 25a, residential lawn and garden uses 27, and agriculture uses 26a. In general, the goal of these updates was to put fewer emissions in overnight hours and to refine the weekday/weekend split for these source categories.

Figure 3-3. Original and updated nonroad day-of-week profiles

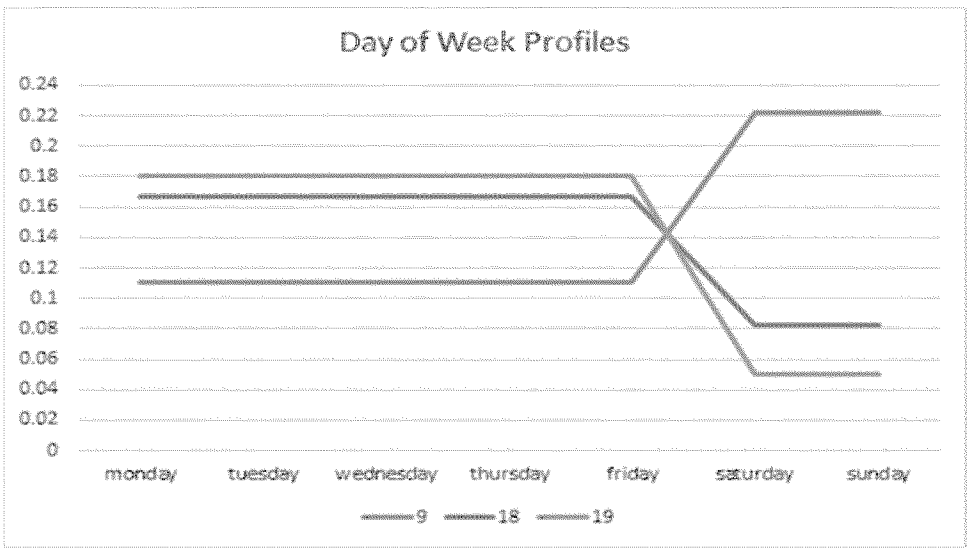
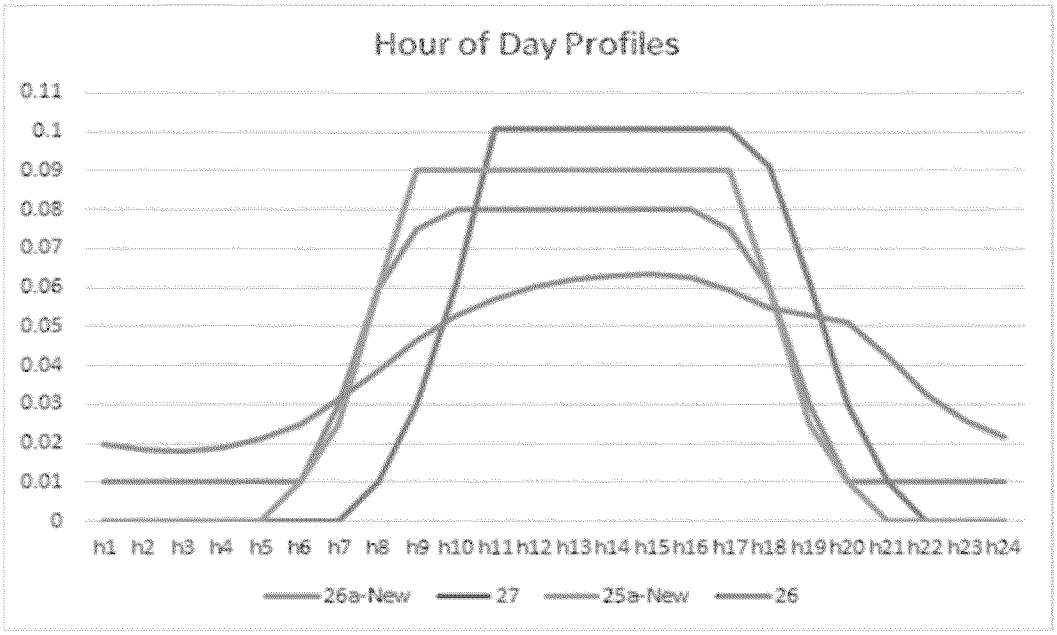


Figure 3-4. Original and updated nonroad hour-of-day profiles



3.3.3 Electric Generating Utility temporal allocation (ptegu)

Base year temporal allocation of EGUs

The 2011NEIv2 annual EGU emissions not matched to CEMS sources are allocated to hourly emissions using the following 3-step methodology: annual value to month, month to day, and day to hour. In the 2011v6.3 platforms, the CEMS data were processed using a tool that reviewed the data quality flags that indicate the data were not measured. Unmeasured data can cause erroneously high values in the CEMS data. If the data were not measured at specific hours, and those values were found to be more than three times the annual mean for that unit, the data for those hours were replaced with annual mean values (Adelman et al., 2012). These adjusted CEMS data were then used for the remainder of the temporalization process described below (see Figure 3-5 for an example). Winter and summer seasons are included in the development of the diurnal profiles as opposed to using data for the entire year because analysis of the hourly CEMS data revealed that there were different diurnal patterns in winter versus summer in many areas. Typically, a single mid-day peak is visible in the summer, while there are morning and evening peaks in the winter as shown in Figure 3-6.

The temporal allocation procedure is differentiated by whether or not the source could be directly matched to a CEMS unit via ORIS facility code and boiler ID. Prior to temporal allocation, as many sources as possible were matched to CEMS data via ORIS facility code and boiler ID. Units were considered matches if the FIPS state/county code matched, the facility name was similar, and the NO_x and SO_2 emissions were similar. The EIS stores a base set of previously matched units via alternate facility and unit IDs. Additions to these matches were made for the 2011v6.3 platform due to additional specificity available in SMOKE but not in EIS, and also based on comments. For any units that are matched, the ORIS facility and boiler ID columns of the point FF10 inventory files are filled with the information on the rows for the corresponding NEI unit. Note that for units matched to CEMS data, annual totals of their emissions may be different than the annual values in 2011NEIv2 because the CEMS data actually replaces the inventory data for the seasons in which the CEMS are operating. If a CEMS-matched unit is determined to be a partial year reporter, as can happen for sources that run CEMS only in

the summer, emissions totaling the difference between the annual emissions and the total CEMS emissions are allocated to the non-summer months.

Figure 3-5. Eliminating unmeasured spikes in CEMS data

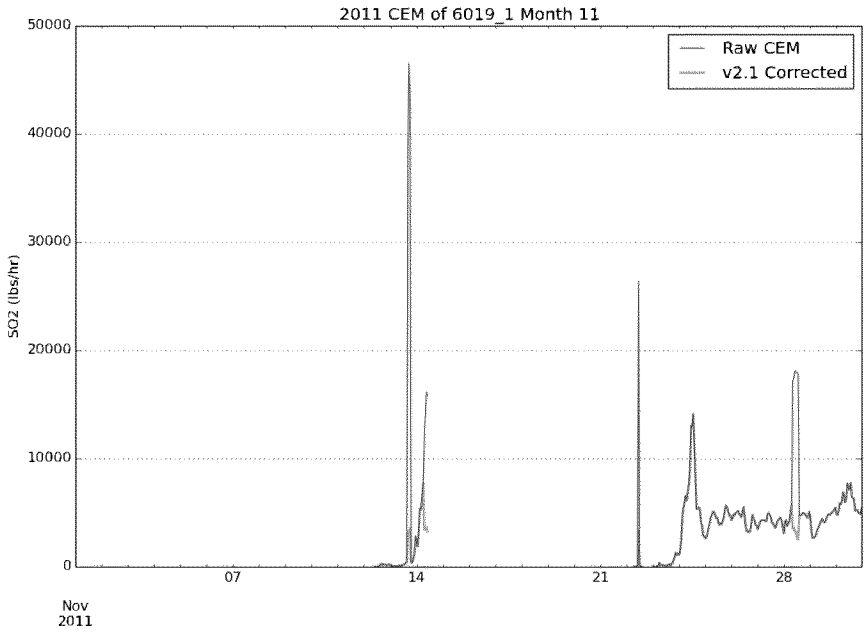
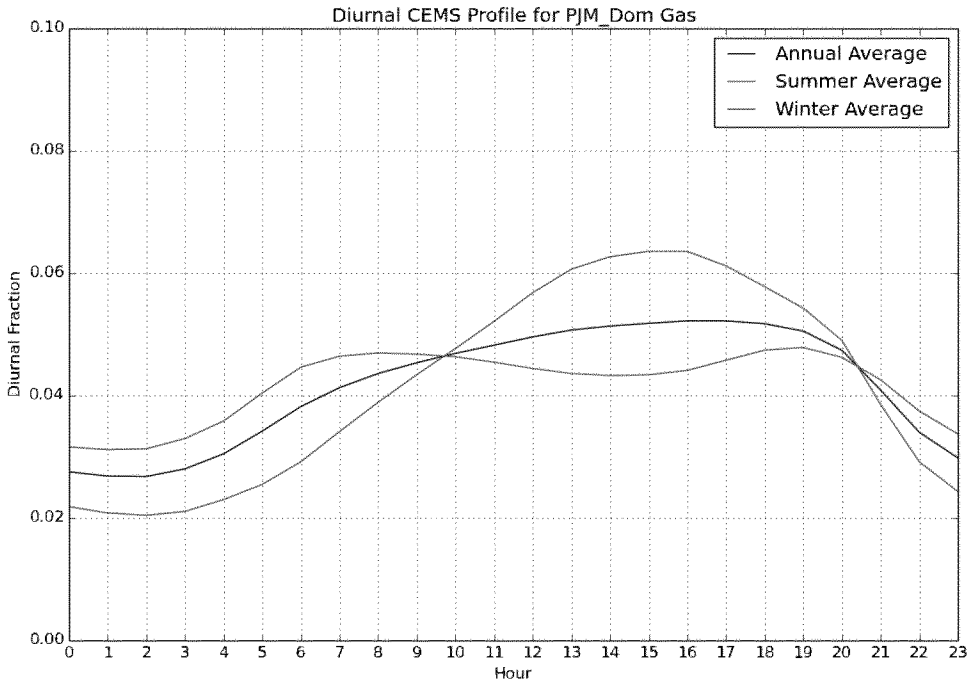


Figure 3-6. Seasonal diurnal profiles for EGU emissions in a Virginia Region



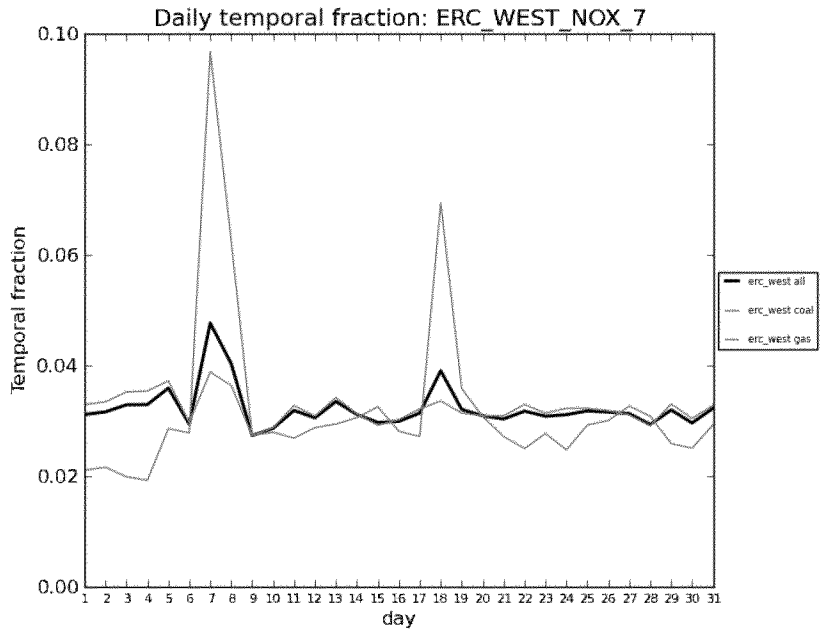
For sources not matched to CEMS units, the allocation of annual emissions to months and then days are done outside of SMOKE and then daily emissions are output to day-specific inventory files. For these

units, the allocation of the inventory annual emissions to months is done using average fuel-specific season-to-month factors generated for each of the 64 IPM regions shown in Figure 3-7. These factors are based on 2011 CEMS data only. In each region, separate factors were developed for the fuels: coal, natural gas, and "other," where the types of fuels included in "other" vary by region. Separate profiles were computed for NO_x, SO_2, and heat input. An overall composite profile was also computed and used when there were no CEMS units with the specified fuel in the region containing the unit. For both CEMS-matched units and units not matched to CEMS, NO_x and SO_2 CEMS data are used to allocate NO_x and SO_2 emissions to monthly emissions, respectively, while heat input data are used to allocate emissions of all other pollutants and to allocate emissions of all pollutants from monthly to daily emissions.

Figure 3-7. IPM Regions in Version 5.16

Daily temporal allocation of units matched to CEMS was performed using a procedure similar to the approach to allocate emissions to months in that the CEMS data replaces the inventory data for each pollutant. For units without CEMS data, emissions were allocated from month to day using IPM-region and fuel-specific average month-to-day factors based on the 2011 CEMS data. Separate month-to-day allocation factors were computed for each month of the year using heat input for the fuels coal, natural gas, and "other" in each region. For both CEMS and non-CEMS matched units, NO_x and SO_2 CEMS data are used to allocate NO_x and SO_2 emissions, while CEMS heat input data are used to allocate all other pollutants. An example of month-to-day profiles for gas, coal, and an overall composite for a region in western Texas is shown in Figure 3-8.

Figure 3-8. Month-to-day profiles for different fuels in a West Texas Region



For units matched to CEMS data, hourly emissions use the hourly CEMS values for NO_x and SO_2, while other pollutants are allocated according to heat input values. For units not matched to CEMS data, temporal profiles from days to hours are computed based on the season-, region- and fuel-specific average day-to-hour factors derived from the CEMS data for those fuels and regions using the appropriate subset of data. For the unmatched units, CEMS heat input data are used to allocate *all* pollutants (including NO_x and SO_2) because the heat input data was generally found to be more complete than the pollutant-specific data. SMOKE then allocates the daily emissions data to hours using the temporal profiles obtained from the CEMS data for the analysis base year (i.e., 2011 in this case).

In the 2011en platform, MWCs and cogeneration units were specified to use flat hourly temporal allocation such that the emissions are allocated to constant levels for every hour of the year. These sources do not use hourly CEMs, and instead use a PTDAY file with the same emissions for each day, combined with a flat hourly temporal profile applied by SMOKE.

Future year temporal allocation of EGUs

For future year temporal allocation of unit-level EGU emissions, estimates of average winter (representing October through April) and average summer (representing May through September) values were provided for all units that submitted CEMS data to EPA as part of the Cross-State Air Pollution Rule and Acid Rain Programs. For the 2023el case, the seasonal emissions were produced by postprocessing of outputs from the Integrated Planning Model (IPM), while for the 2023en case the unit-level emissions were developed using an engineering analysis approach (see Section 4.1 for more details). For both cases, the unit-level data was converted into hourly values through the temporal allocation process using a 3-step methodology: annualized summer/winter value to month, month to day, and day to hour. CEMS data from the air quality analysis year (e.g., 2011) is used as much as possible to temporally allocate the EGU emissions. In the 2011v6.3 platforms, temporal profiles are developed in SMOKE temporal profile formats instead of the earlier method of some temporal allocation being done by SMOKE and some by external programs.

The goal of the temporal allocation process is to reflect the variability in the unit-level emissions that can impact air quality over seasonal, daily, or hourly time scales, in a manner compatible with incorporating future-year emission projections into future-year air quality modeling. The temporal allocation process is applied to the seasonal emission projections for two seasons: summer (May through September) and winter (October through April). The Flat File used as the input to the temporal allocation process contains unit-level emissions and stack parameters (i.e., stack location and other characteristics consistent with information found in the NEI). When the flat file is produced from post-processed IPM outputs, a cross reference is used to map the units in the IPM National Electric Energy Database System (NEEDS) database to the stack parameter and facility, unit, release point, and process identifiers used in the NEI. The cross reference also maps sources to the hourly CEMS data used to temporally allocate the emissions in the base year air quality modeling. For the 2023el case, the v5.16 cross reference information along with other key inputs to the flat file generation process are in the file IPM5.16_FlatFile_Inputs.xlsx that is available in the reports section of the 2011v6.3 platform FTP area: ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/reports/. Note that for 2023en, this file is not used because the 2023en EGU emissions were not generated using IPM.

For units that had seasonal information provided in the future year flat file, the monthly values in the Flat File input to the temporal allocation process are computed by multiplying the average summer day and average winter day emissions by the number of days in the respective month. In summary, the monthly emission values shown in the Flat File are not intended to represent an actual month-to-month emission pattern. Instead, they are interim values that have translated IPM's seasonal projections into month-level data that serve as a starting point for the temporal allocation process. In 2023en, units without CEMS data only had annual emissions specified. For those units, monthly temporalization factors were generated by source and pollutant based on 2011en emissions. These factors were then applied to the 2023en annual emissions to create the 2023en monthly emissions.

The monthly emissions within the Flat File undergo a multi-step temporal allocation process to yield the hourly emission values at each unit, as is needed for air quality modeling: summer or winter value to month, month to day, and day to hour. For sources not matched to unit-specific CEMS data, the first two steps are done outside of SMOKE and the third step to get to hourly values is done by SMOKE using the daily emissions files created from the first two steps. For each of these three temporal allocation steps, NO_x and SO_2 CEMS data are used to allocate NO_x and SO_2 emissions, while CEMS heat input data are used to allocate all other pollutants. The approach defined here gives priority to temporalization based on the base year CEMS data to the maximum extent possible for both base and future year modeling.

Prior to using the 2011 CEMS data to develop monthly, daily, and hourly profiles, the CEMS data were processed through a tool that found data quality flags that indicated the data were measured. These adjusted CEMS data were used to compute the monthly, daily, and hourly profiles described below.

For units that have CEMS data available and that have CEMS units match to the NEI sources, the emissions are temporalized based on the CEMS data for that unit and pollutant. For units that are not matched to the NEI or for which CEMS data are not available, the allocation of the seasonal emissions to months is done using average fuel-specific season-to-month factors generated for each of the 64 IPM regions shown in Figure 3-7. These factors are based on a single year of CEMS data for the modeling base year associated with the air quality modeling analysis being performed, such as 2011. The fuels used for creating the profiles for a region are coal, natural gas, and other, where the other fuels used include oil and wood and vary by region. Separate profiles are computed for NO_x, SO_2, and heat input. An overall composite profile across all fuels is also computed and can be used in the event that a region has too few

units of a fuel type to make a reasonable average profile, or in the case when a unit changes fuels between the base and future year and there were previously no units with that fuel in the region containing the unit.

The monthly emission values in the Flat File are first reallocated across the months in that season to align the month-to-month emission pattern at each stack with historic seasonal emission patterns[18]. While this reallocation affects the monthly pattern of each unit's future-year seasonal emissions, the seasonal totals are held equal to the IPM projection for that unit and season. Second, the reallocated monthly emission values at each stack are disaggregated down to the daily level consistent with historic daily emission patterns in the given month at the given stack using separate profiles for NO_x, SO_2, and heat input. This process helps to capture the influence of meteorological episodes that cause electricity demand to vary from day-to-day, as well as weekday-weekend effects that change demand during the course of a given week. Third, this data set of emission values for each day of the year at each unit is input into SMOKE, which uses temporal profiles to disaggregate the daily values into specific values for each hour of the year.

For units without or not matched to CEMS data, or for which the CEMS data are found to be unsuitable for use in the future year, emissions are allocated from month to day using IPM-region and fuel-specific average month-to-day factors based on CEMS data from the base year of the air quality modeling analysis. These instances include units that did not operate in the base year or for which it may not have been possible to match the unit to a specific unit in the NEI. Average profiles are used for some units with CEMS data in the base year when one of the following cases is true: (1) units are projected to have substantially increased emissions in the future year compared to its emissions in the base (historic) year[19]; (2) CEMS data are only available for a limited number of hours in that base year; (3) units change fuels in the future year; (4) the unit is new in the future year; (5) when there are no CEMS data for one season in the base year but IPM runs the unit during both seasons; or (6) units experienced atypical conditions during the base year, such as lengthy downtimes for maintenance or installation of controls. The temporal profiles that map emissions from days to hours are computed based on the region and fuel-specific seasonal (i.e., winter and summer) average day-to-hour factors derived from the CEMS data for those fuels and regions using only heat input data for that season. Only heat input is used because it is the variable that is the most complete in the CEMS data. SMOKE uses these profiles to allocate the daily emissions data to hours.

The emissions from units for which unit-specific profiles are not used are temporally allocated to hours reflecting patterns typical of the region in which the unit is located. Analysis of CEMS data for units in each of the 64 IPM regions revealed that there were differences in the temporal patterns of historic emission data that correlate with fuel type (e.g., coal, gas, and other), time of year, pollutant, season (i.e., winter versus summer) and region of the country. The correlation of the temporal pattern with fuel type is explained by the relationship of units' operating practices with the fuel burned. For example, coal units take longer to ramp up and ramp down than natural gas units, and some oil units are used only when electricity demand cannot otherwise be met. Geographically, the patterns were less dependent on state location than they were on IPM regional location. For temporal allocation of emissions at these units,

[18] For example, the total emissions for a unit in May would not typically be the same as the total emissions for the same unit in July, even though May and July are both in the summer season and the number of days in those months is the same. This is because the weather changes over the course of each season, and thus the operating behavior of a specific unit can also vary throughout each season. Therefore, part of the temporal allocation process is intended to create month-specific emissions totals that reflect this intra-seasonal variation in unit operation and associated emissions.

[19] In such instances, the EPA does not use that unit's CEMS data for temporal allocation in order to avoid assigning large increases in emissions over short time periods in the unit's hourly emission profile.

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Figure 3-8 provides an example of daily coal, gas, and composite profiles in one IPM region. The EPA developed seasonal average emission profiles, each derived from base year CEMS data for each season across all units sharing both IPM region and fuel type[20]. Figure 3-6 provides an example of seasonal profiles that allocate daily emissions to hours in one IPM region. These average day-to-hour temporal profiles were also used for sources during seasons of the year for which there were no CEMS data available, but for which IPM predicted emissions in that season. This situation can occur for multiple reasons, including how the CEMS was run at each source in the base year.
For units that do have CEMS data in the base year and are matched to units in the IPM output, the base year CEMS data are scaled so that their seasonal emissions match the IPM-projected totals. In particular, the fraction of the unit's seasonal emissions in the base year is computed for each hour of the season, and then applied to the seasonal emissions in the future year. Any pollutants other than NO_x and SO_2 are temporally allocated using heat input as a surrogate. Distinct factors are used for the fuels coal, natural gas, and "other." Through the temporal allocation process, the future year emissions have the same temporal pattern as the base year CEMS data while the future-year seasonal total emissions for each unit match the future-year unit-specific projection for each season (see example in Figure 3-9).

In cases when the emissions for a particular unit are projected to be substantially higher in the future year than in the base year, the proportional scaling method to match the emission patterns in the base year described above can yield emissions for a unit that are much higher than the historic maximum emissions for that unit. To help address this issue in the future case, the maximum measured emissions of NO_x and SO_2 in the period of 2011-2014 were computed. The temporally allocated emissions were then evaluated at each hour to determine whether they were above this maximum. The amount of "excess emissions" over the maximum was then computed. For units for which the "excess emissions" could be reallocated to other hours, those emissions were distributed evenly to hours that were below the maximum. Those hourly emissions were then reevaluated against the maximum, and the procedure of reallocating the excess emissions to other hours was repeated until all of the hours had emissions below the maximum, whenever possible (see example in Figure 3-10).

[20] The EPA also uses an overall composite profile across all fuels for each IPM region in instances where a unit is projected to burn a fuel for which the EPA cannot construct an average emission profile (because there were no other units in that IPM region whose historic CEMS data represent emissions from burning that fuel).

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Figure 3-9. Future year emissions follow pattern of base year emissions

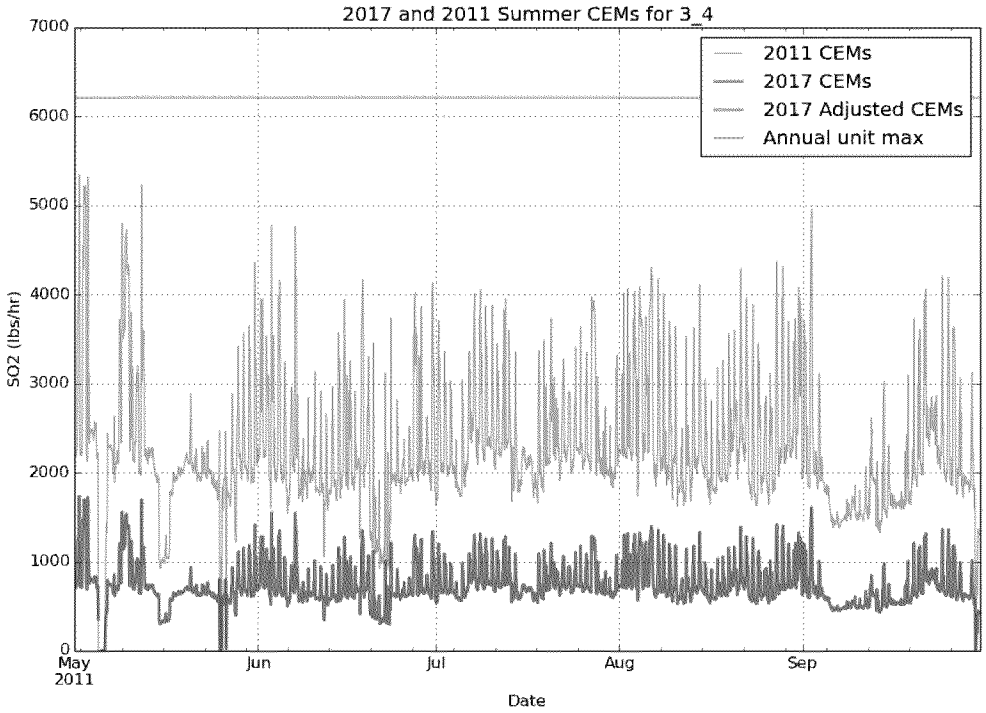
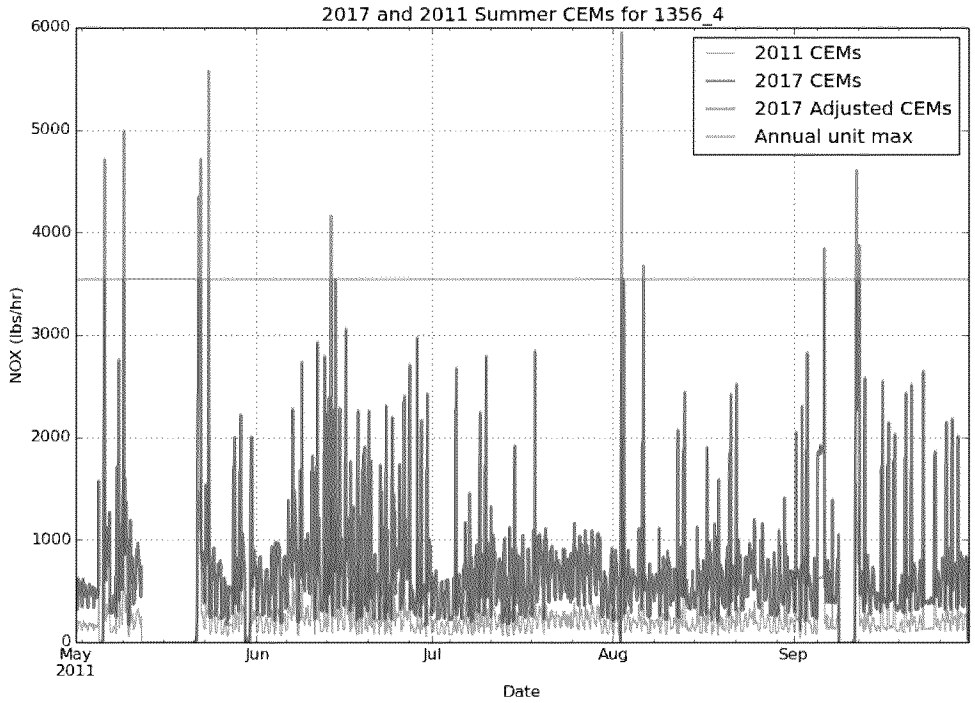


Figure 3-10. Excess emissions apportioned to hours less than maximum



Using the above approach, it was not always possible to reallocate excess emissions to hours below the historic maximum, such as when the total seasonal emissions of NO_x or SO_2 for a unit divided by the number of hours of operation are greater than the 2011-2014 maximum emissions level. For these units,

the *regional* fuel-specific average profile was applied to all pollutants, including heat input, for that season (see example in Figure 3-11). An exception to this is if the fuel for that unit is not gas or coal. In that case, the composite (non-fuel-specific) profile was used for that unit. This is because many sources that used "other" fuel profiles had very irregular shapes due to a small number of sources in the region, and the allocated emissions frequently still exceeded the 2011-2014 maximum. Note that it was not possible for SMOKE to use regional profiles for some pollutants and adjusted CEMS data for other pollutants for the same unit/season, therefore, all pollutants are assigned to regional profiles when regional profiles are needed. Also note that for some units, some hours still exceed the 2011-2014 annual maximum for the unit even after regional profiles were applied (see example in Figure 3-12).

For more information on the development of IPM emission estimates for the 2011el case and the temporalization of those, see the IPM 5.16 section of https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling, in particular the Air Quality Modeling Flat File Documentation and accompanying inputs.

Figure 3-11. Adjustment to Hours Less than Maximum Not Possible so Regional Profile Applied

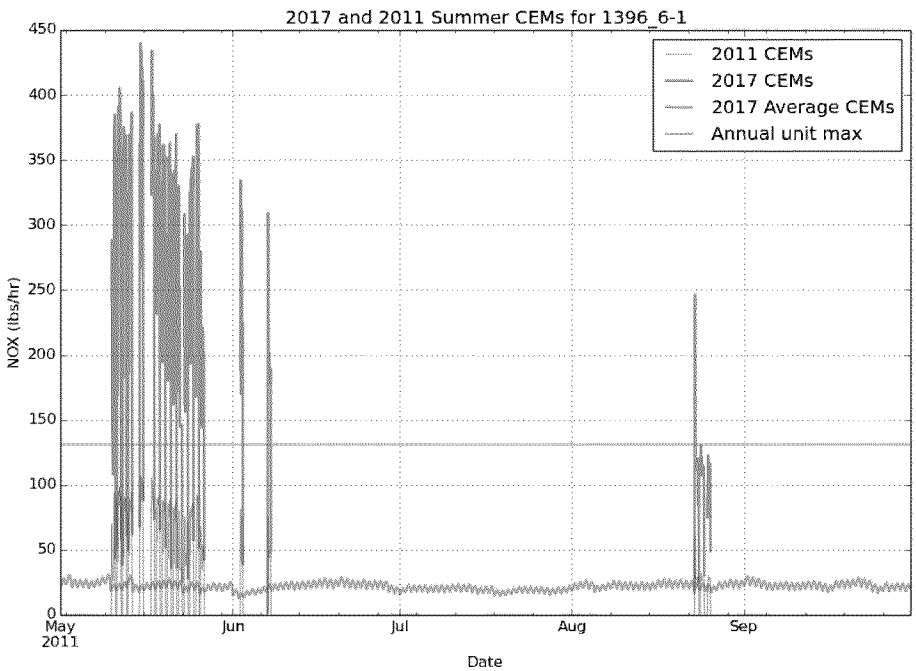
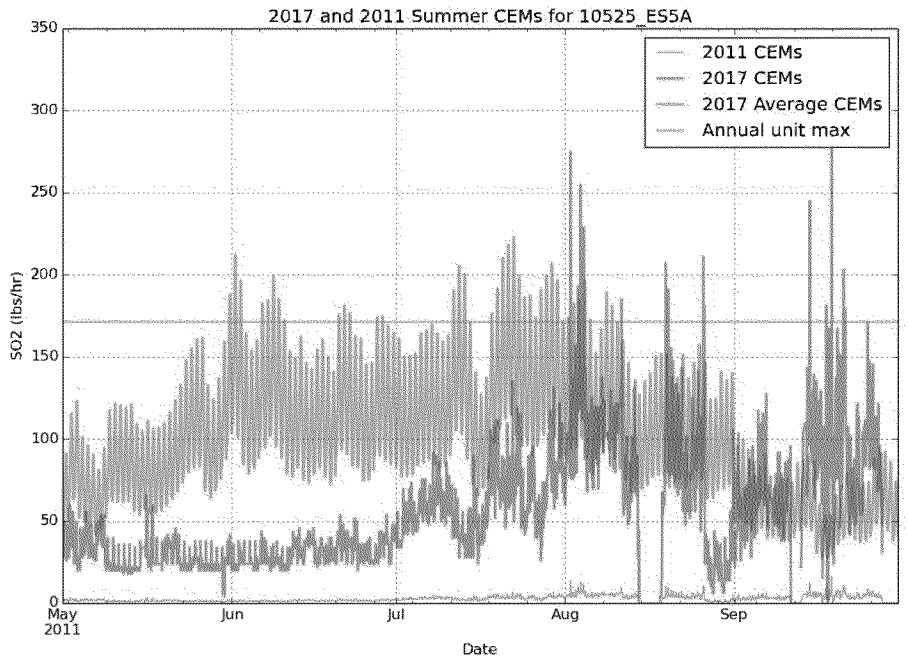


Figure 3-12. Regional Profile Applied, but Exceeds Maximum in Some Hours



3.3.4 Residential Wood Combustion Temporalization (rwc)

There are many factors that impact the timing of when emissions occur, and for some sectors this includes meteorology. The benefits of utilizing meteorology as method for temporalization are: (1) a meteorological dataset consistent with that used by the AQ model is available (e.g., outputs from WRF); (2) the meteorological model data are highly resolved in terms of spatial resolution; and (3) the meteorological variables vary at hourly resolution and can therefore be translated into hour-specific temporalization.

The SMOKE program GenTPRO provides a method for developing meteorology-based temporalization. Currently, the program can utilize three types of temporal algorithms: annual-to-day temporalization for residential wood combustion (RWC); month-to-hour temporalization for agricultural livestock NH_3; and a generic meteorology-based algorithm for other situations. For the 2011 platform, meteorological-based temporalization was used for portions of the rwc sector and for livestock within the ag sector.

GenTPRO reads in gridded meteorological data (output from MCIP) along with spatial surrogates, and uses the specified algorithm to produce a new temporal profile that can be input into SMOKE. The meteorological variables and the resolution of the generated temporal profile (hourly, daily, etc.) depend on the selected algorithm and the run parameters. For more details on the development of these algorithms and running GenTPRO, see the GenTPRO documentation and the SMOKE documentation at http://www.cmascenter.org/smoke/documentation/3.1/GenTPRO_TechnicalSummary_Aug2012_Final.pdf and https://www.cmascenter.org/smoke/documentation/3.7/html/ch05s03s06.html, respectively.

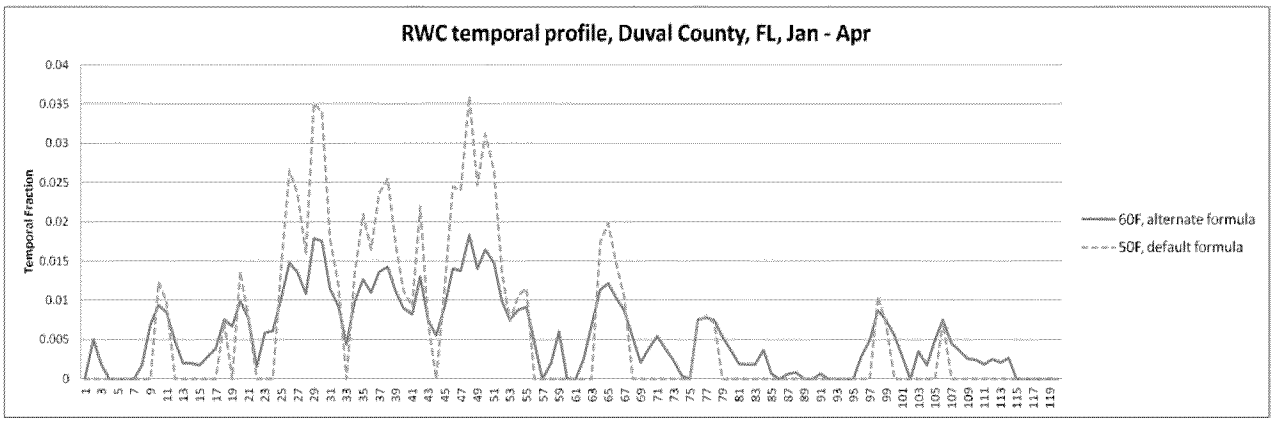
As of the 2011v6.2 platform and in SMOKE 3.6.5, the temporal profile format was updated. GenTPRO now produces separate files including the monthly temporal profiles (ATPRO_MONTHLY) and day-of-month temporal profiles (ATPRO_DAILY), instead of a single ATPRO_DAILY with day-of-year temporal profiles as it did in SMOKE 3.5. The results are the same either way, so the temporal profiles

themselves are effectively the same in 2011v6.2 as they were in 2011v6.0 since the meteorology is the same, but they are formatted differently.

For the RWC algorithm, GenTPRO uses the daily minimum temperature to determine the temporal allocation of emissions to days. GenTPRO was used to create an annual-to-day temporal profile for the RWC sources. These generated profiles distribute annual RWC emissions to the coldest days of the year. On days where the minimum temperature does not drop below a user-defined threshold, RWC emissions for most sources in the sector are zero. Conversely, the program temporally allocates the largest percentage of emissions to the coldest days. Similar to other temporal allocation profiles, the total annual emissions do not change, only the distribution of the emissions within the year is affected. The temperature threshold for rwc emissions was 50 ˚F for most of the country, and 60 ˚F for the following states: Alabama, Arizona, California, Florida, Georgia, Louisiana, Mississippi, South Carolina, and Texas.

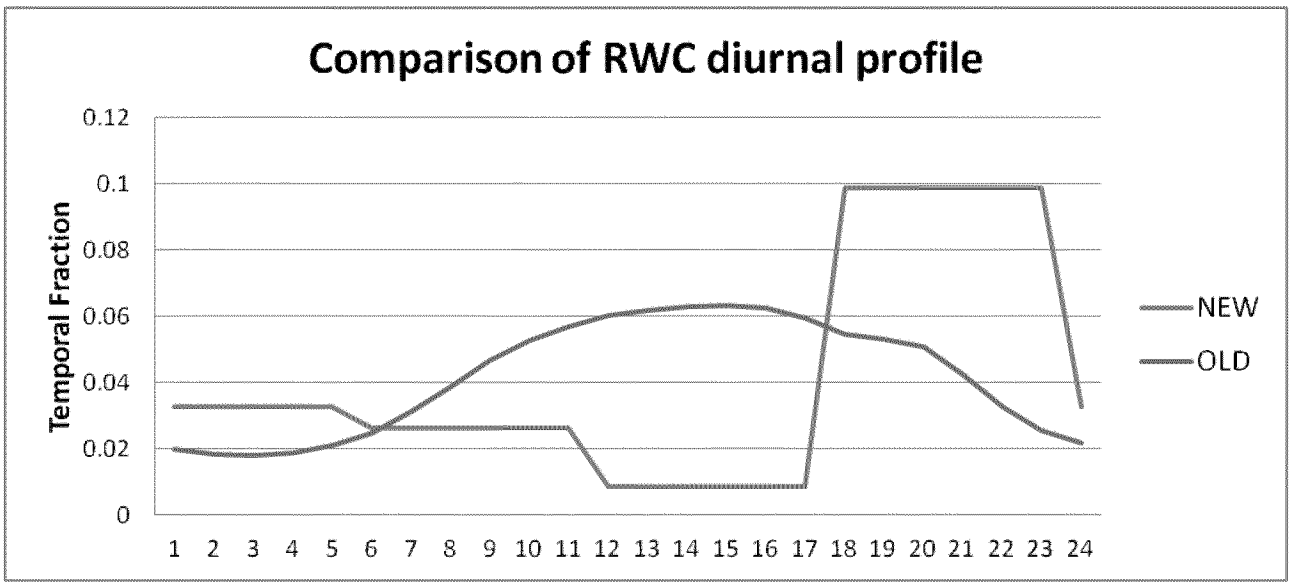
Figure 3-13 illustrates the impact of changing the temperature threshold for a warm climate county. The plot shows the temporal fraction by day for Duval County, Florida, for the first four months of 2007. The default 50 ˚F threshold creates large spikes on a few days, while the 60 ˚F threshold dampens these spikes and distributes a small amount of emissions to the days that have a minimum temperature between 50 and 60 ˚F.

Figure 3-13. Example of RWC temporalization in 2007 using a 50 versus 60 ˚F threshold



The diurnal profile for used for most RWC sources (see Figure 3-14) places more of the RWC emissions in the morning and the evening when people are typically using these sources. This profile is based on a 2004 MANE-VU survey based temporal profiles (see http://www.marama.org/publications_folder/ResWoodCombustion/Final_report.pdf). This profile was created by averaging three indoor and three RWC outdoor temporal profiles from counties in Delaware and aggregating them into a single RWC diurnal profile. This new profile was compared to a concentration based analysis of aethalometer measurements in Rochester, New York (Wang *et al.* 2011) for various seasons and day of the week and found that the new RWC profile generally tracked the concentration based temporal patterns.

Figure 3-14. RWC diurnal temporal profile



The temporalization for "Outdoor Hydronic Heaters" (i.e., "OHH," SCC=2104008610) and "Outdoor wood burning device, NEC (fire-pits, chimneas, etc.)" (i.e., "recreational RWC," SCC=21040087000) were updated because the meteorological-based temporalization used for the rest of the rwc sector did not agree with observations for how these appliances are used.

For OHH, the annual-to-month, day-of-week and diurnal profiles were modified based on information in the New York State Energy Research and Development Authority's (NYSERDA) "Environmental, Energy Market, and Health Characterization of Wood-Fired Hydronic Heater Technologies, Final Report" (NYSERDA, 2012), as well as a Northeast States for Coordinated Air Use Management (NESCAUM) report "Assessment of Outdoor Wood-fired Boilers" (NESCAUM, 2006). A Minnesota 2008 Residential Fuelwood Assessment Survey of individual household responses (MDNR, 2008) provided additional annual-to-month, day-of-week and diurnal activity information for OHH as well as recreational RWC usage.

The diurnal profile for OHH, shown in Figure 3-15, is based on a conventional single-stage heat load unit burning red oak in Syracuse, New York. As shown in Figure 3-16, the NESCAUM report describes how for individual units, OHH are highly variable day-to-day but that in the aggregate, these emissions have no day-of-week variation. In contrast, the day-of-week profile for recreational RWC follows a typical "recreational" profile with emissions peaked on weekends.

Annual-to-month temporalization for OHH as well as recreational RWC were computed from the MDNR 2008 survey and are illustrated in Figure 3-17. The OHH emissions still exhibit strong seasonal variability, but do not drop to zero because many units operate year round for water and pool heating. In contrast to all other RWC appliances, recreational RWC emissions are used far more frequently during the warm season.

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Figure 3-15. Diurnal profile for OHH, based on heat load (BTU/hr)

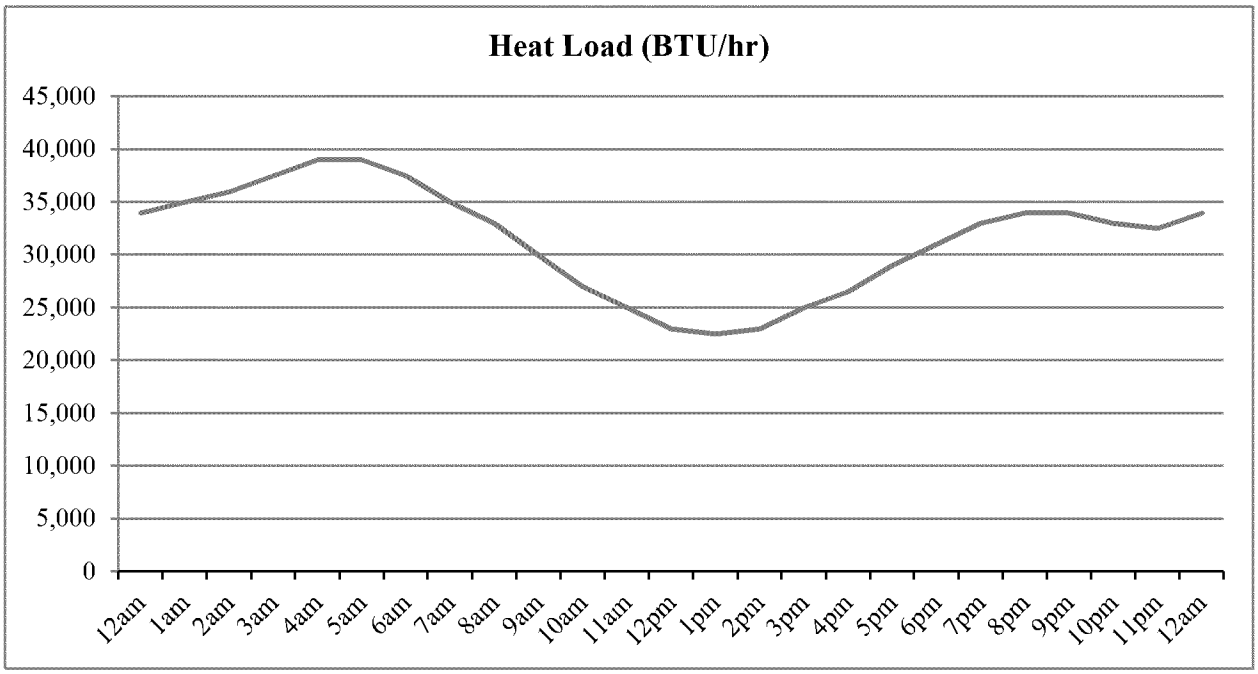

Figure 3-16. Day-of-week temporal profiles for OHH and Recreational RWC

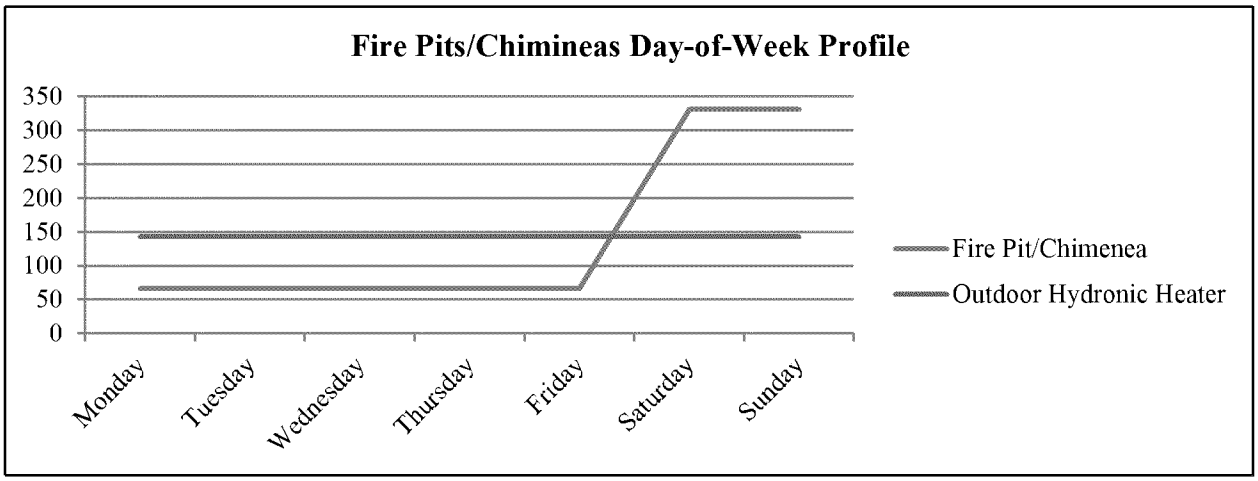

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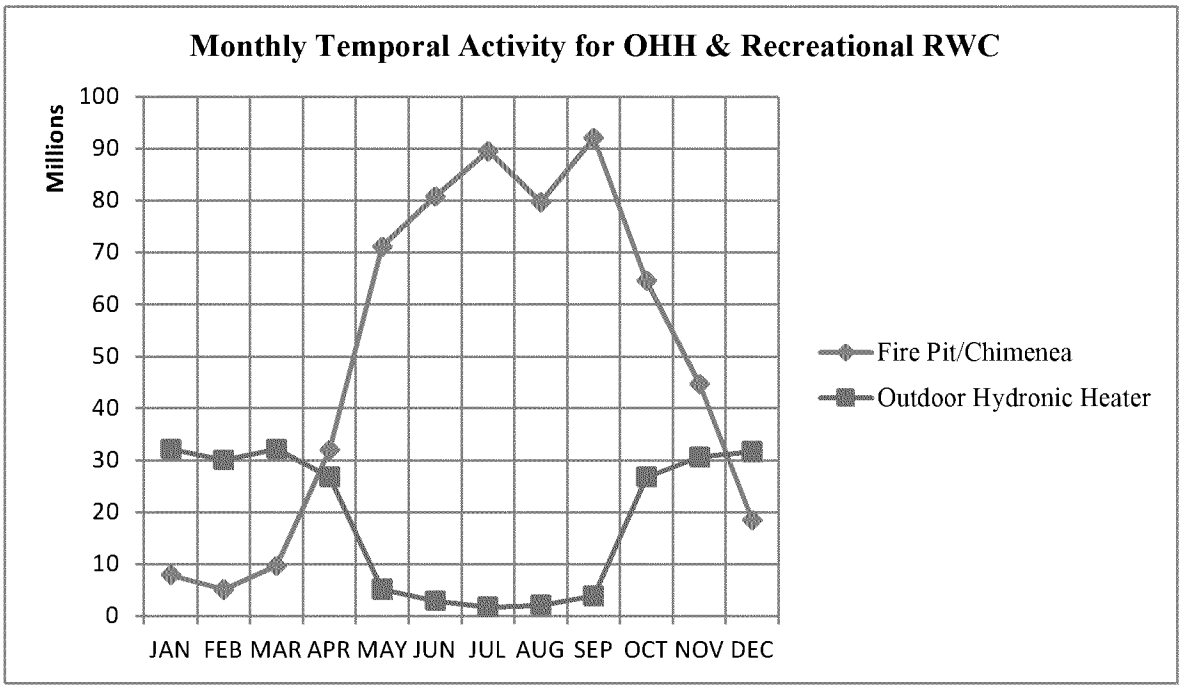
Figure 3-17. Annual-to-month temporal profiles for OHH and recreational RWC



3.3.5 Agricultural Ammonia Temporal Profiles (ag)

For the agricultural livestock NH_3 algorithm, the GenTPRO algorithm is based on an equation derived by Jesse Bash of the EPA's ORD based on the Zhu, Henze, et al. (2013) empirical equation. This equation is based on observations from the TES satellite instrument with the GEOS-Chem model and its adjoint to estimate diurnal NH3 emission variations from livestock as a function of ambient temperature, aerodynamic resistance, and wind speed. The equations are:

$$E_{i,h} = [161500/T_{i,h} \text{ x } e^{(-1380/T_{i,h})}] \text{ x } AR_{i,h}$$

$$PE_{i,h} = E_{i,h} / \text{Sum}(E_{i,h})$$

where

- $PE_{i,h}$ = Percentage of emissions in county *i* on hour *h*
- $E_{i,h}$ = Emission rate in county *i* on hour *h*
- $T_{i,h}$ = Ambient temperature (Kelvin) in county *i* on hour *h*
- $V_{i,h}$ = Wind speed (meter/sec) in county *i* (minimum wind speed is 0.1 meter/sec)
- $AR_{i,h}$ = Aerodynamic resistance in county *i*

GenTPRO was run using the "BASH_NH3" profile method to create month-to-hour temporal profiles for these sources. Because these profiles distribute to the hour based on monthly emissions, the monthly emissions are obtained from a monthly inventory, or from an annual inventory that has been temporalized to the month. Figure 3-18 compares the daily emissions for Minnesota from the "old" approach (uniform monthly profile) with the "new" approach (GenTPRO generated month-to-hour profiles). Although the GenTPRO profiles show daily (and hourly variability), the monthly total emissions are the same between the two approaches.

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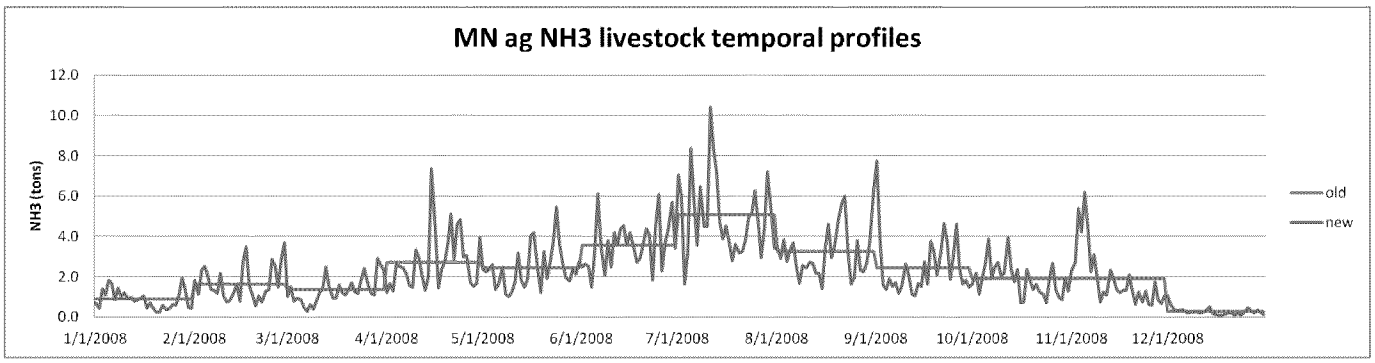
Figure 3-18. Example of animal NH_3 emissions temporalization approach, summed to daily emissions



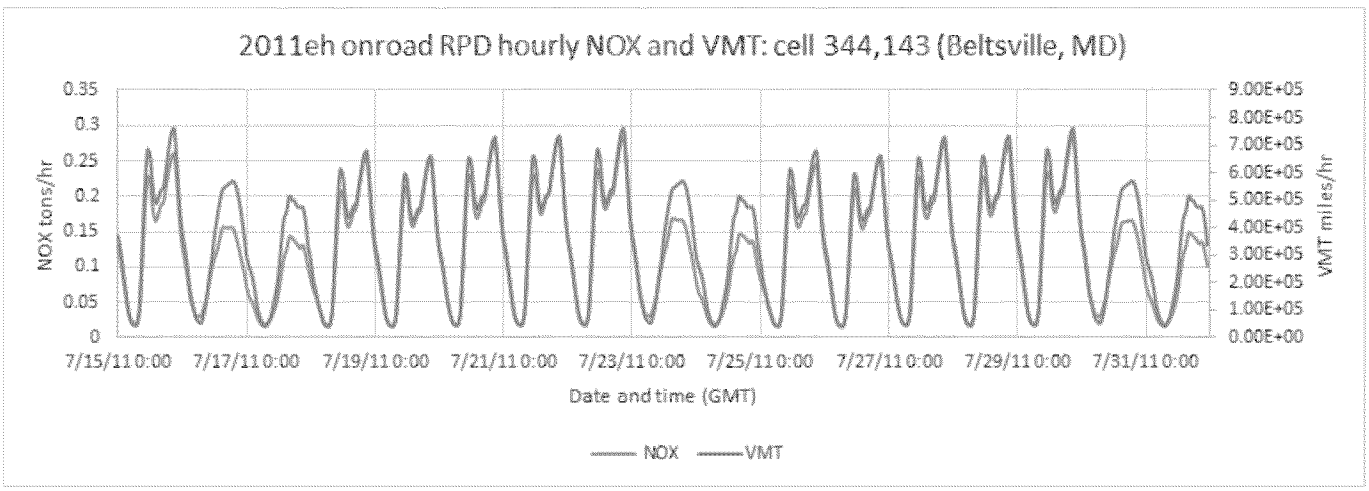
3.3.6 Onroad mobile temporalization (onroad)

For the onroad sector, the temporal distribution of emissions is a combination of more traditional temporal profiles and the influence of meteorology. This section will discuss both the meteorological influences and the diurnal temporal profiles for this platform.

Meteorology is not used in the development of the temporal profiles, but rather it impacts the calculation of the hourly emissions through the program Movesmrg. The result is that the emissions vary at the hourly level by grid cell. More specifically, the on-network (RPD) and the off-network parked vehicle (RPV, RPH, and RPP) processes use the gridded meteorology (MCIP) directly. Movesmrg determines the temperature for each hour and grid cell and uses that information to select the appropriate emission factor for the specified SCC/pollutant/mode combination. In the 2011 platform (and for the 2011NEIv2), RPP was updated to use the gridded minimum and maximum temperature for the day. This more spatially resolved temperature range produces more accurate emissions for each grid cell. The combination of these four processes (RPD, RPV, RPH, and RPP) is the total onroad sector emissions. The onroad sector show a strong meteorological influence on their temporal patterns (see the 2011NEIv2 TSD for more details).

Figure 3-19 illustrates the temporalization of the onroad sector and the meteorological influence via SMOKE-MOVES. Similar temporalization is done for the VMT in SMOKE-MOVES, but the meteorologically varying emission factors add an additional variation on top of the temporalization.

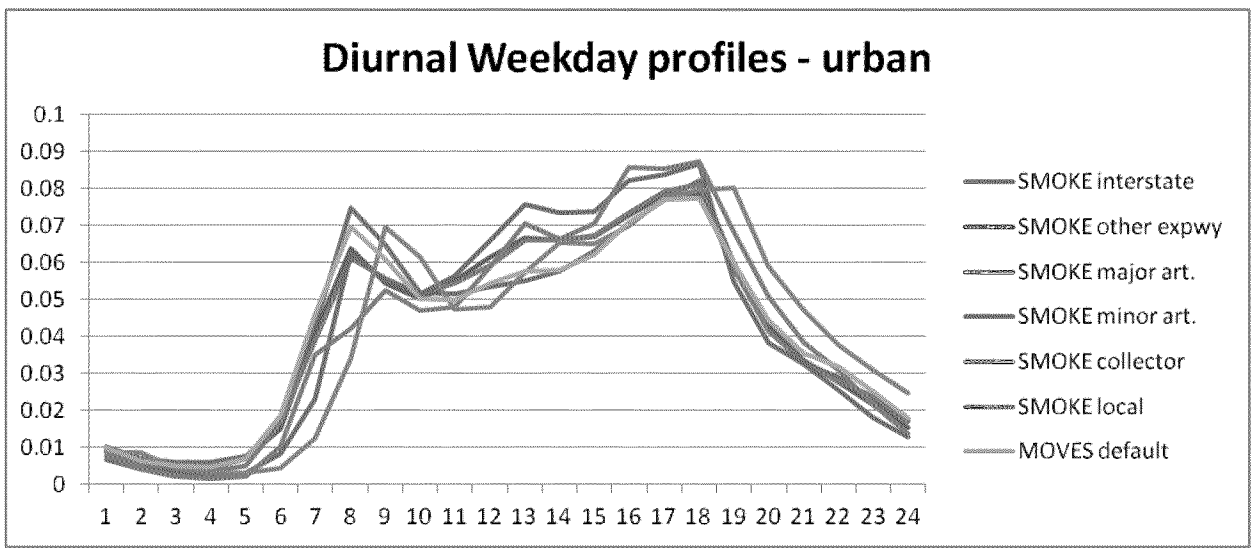
Figure 3-19. Example of SMOKE-MOVES temporal variability of NO_X emissions



For the onroad sector, the "inventories" referred to in Table 3-17 actually consist of activity data, not emissions. For RPP and RPV processes, the VPOP inventory is annual and does not need temporalization. For RPD, the VMT inventory is monthly and was temporalized to days of the week and then to hourly VMT through temporal profiles. The RPD processes require a speed profile (SPDPRO) that consists of vehicle speed by hour for a typical weekday and weekend day. Unlike other sectors, the temporal profiles and SPDPRO will impact not only the distribution of emissions through time but also the total emissions. Because SMOKE-MOVES (for RPD) calculates emissions from VMT, speed and meteorology, if one shifted the VMT or speed to different hours, it would align with different temperatures and hence different emission factors. In other words, two SMOKE-MOVES runs with identical annual VMT, meteorology, and MOVES emission factors, will have different total emissions if the temporalization of VMT changes. For RPH, the HOTELING inventory is monthly and was temporalized to days of the week and to hour of the day through temporal profiles. This is an analogous process to RPD except that speed is not included in the calculation of RPH.

In previous platforms, the diurnal profile for VMT[21] varied by road type but not by vehicle type (see Figure 3-20). These profiles were used throughout the nation.

Figure 3-20. Previous onroad diurnal weekday profiles for urban roads



Diurnal profiles that could differentiate by vehicle type as well as by road type and would potentially vary over geography were desired. In the development of the 2011v6.0[22] platform, the EPA updated these profiles to include information submitted by states in their MOVES county databases (CDBs). The 2011NEIv2 process provided an opportunity to update these diurnal profile with new information submitted by states, to supplement the data with additional sources, and to refine the methodology.

States submitted MOVES county databases (CDBs) that included information on the distribution of VMT by hour of day and by day of week[23] (see the 2011NEIv2 TSD for details on the submittal process for onroad). The EPA mined the state submitted MOVES CDBs for non-default diurnal profiles[24]. The list

[21] These profiles were used in the 2007 platform and proceeding platforms.
[22] These profiles that were generated from MOVES submittals only were used for the v6 and v6.1 platforms. See their respective TSDs for more details.
[23] The MOVES tables are the hourvmtfraction and the dayvmtfraction.
[24] Further QA was done to remove duplicates and profiles that were missing two or more hours. If they were missing a single hour, the missing hour could be calculated by subtracting all other hours fractions from 1.

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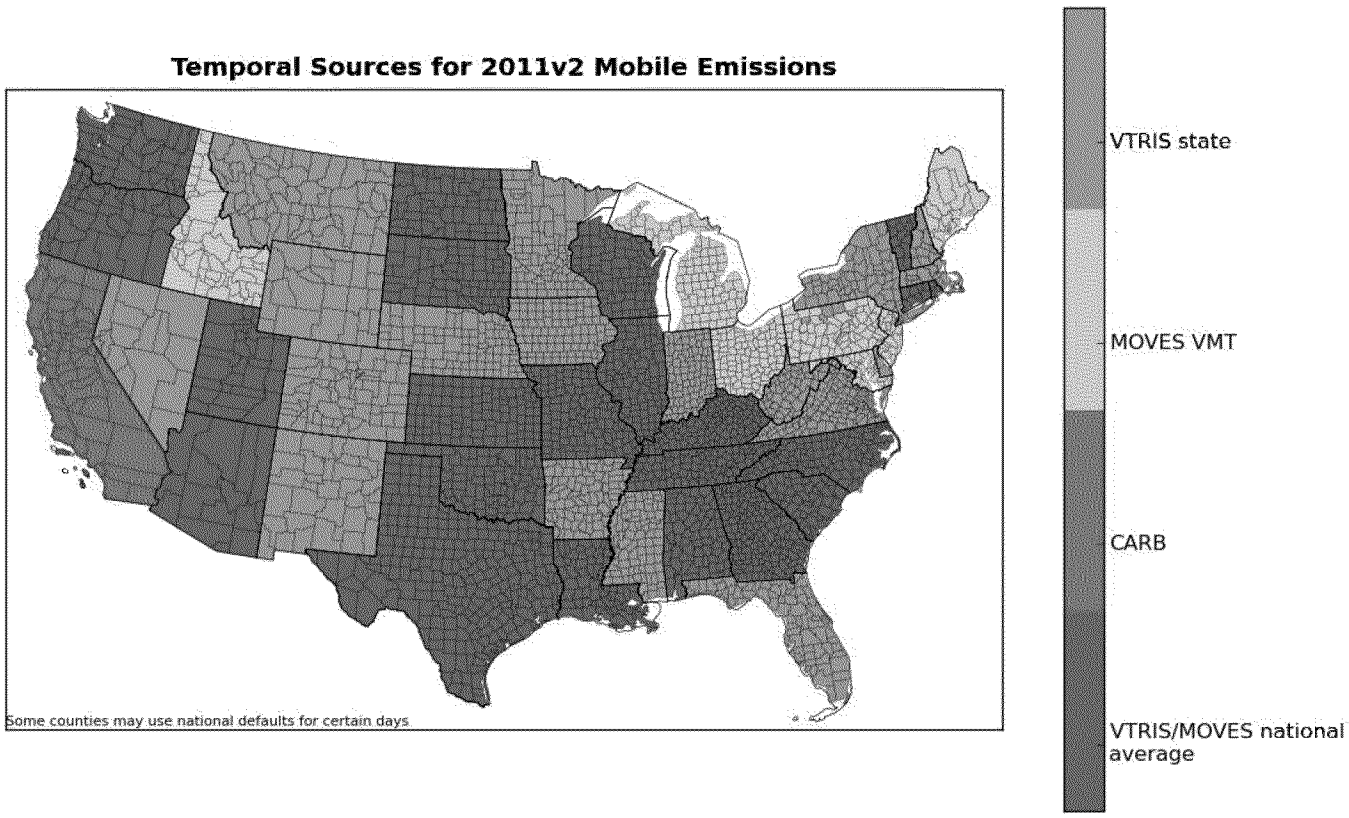
of potential diurnal profiles was then analyzed to see whether the profiles varied by vehicle type, road type, weekday versus weekend, and by county within a state. For the MOVES diurnal profiles, the EPA only considered the state profiles that varied significantly by both vehicle and road types. Only those profiles that passed this criteria were used in that state or used in developing default temporal profiles. The Vehicle Travel Information System (VTRIS) is a repository for reported traffic count data to the Federal Highway Administration (FHWA). The EPA used 2012 VTRIS data to create additional temporal profiles for states that did not submit temporal information in their CDBs or where those profiles did not pass the variance criteria. The VTRIS data were used to create state specific diurnal profiles by HPMS vehicle and road type. The EPA created distinct diurnal profiles for weekdays, Saturday and Sunday along with day of the week profiles[25].

The EPA attempted to maximize the use of state and/or county specific diurnal profiles (either from MOVES or VTRIS). Where there was no MOVES or VTRIS data, then a new default profile would be used (see below for description of new profiles). This analysis was done separately for weekdays and for weekends and, therefore, some areas had submitted profiles for weekdays but defaults for weekends. The result was a set of profiles that varied geographically depending on the source of the profile and the characteristics of the profiles (see Figure 3-21).

Figure 3-21. Use of submitted versus new national default profiles



A new set of diurnal profiles was developed for the 2011v6.2 platform from the submitted profiles that varied by both vehicle type and road type. For the purposes of constructing the national default diurnal profiles, the EPA created individual profiles for each state (averaging over the counties within) to create a

[25] Note, the day of the week profiles (i.e., Monday vs Tuesday vs etc) are only from the VTRIS data. The MOVES CDBs only have weekday versus weekend profiles so they were not included in calculating a new national default day of the week profile.

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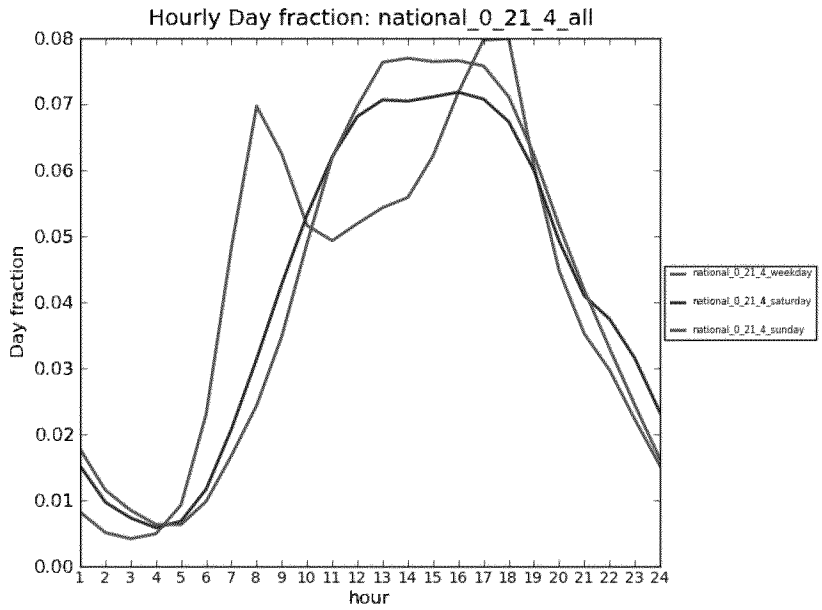
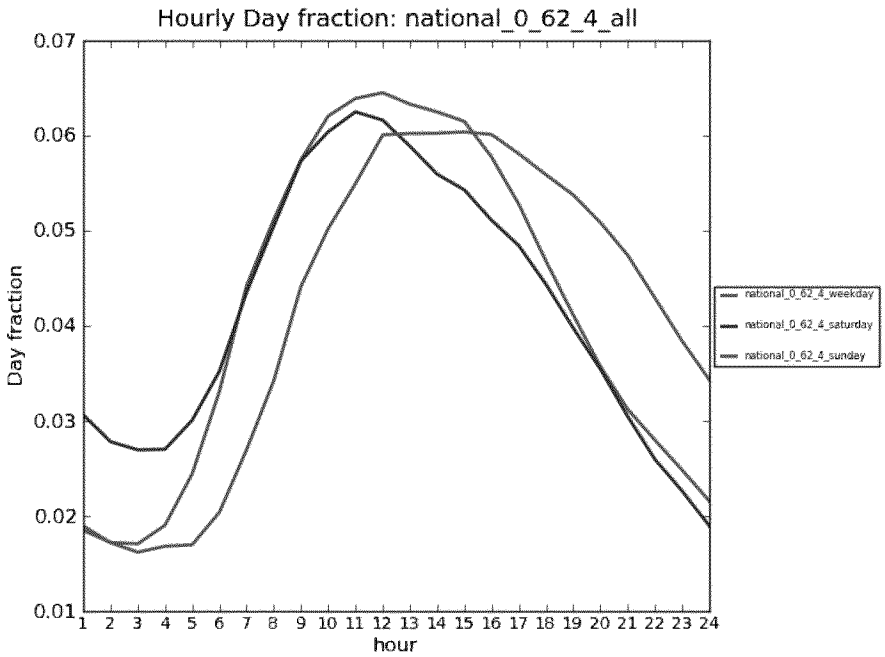
single profile by state, vehicle type, road type, and the day (i.e., weekday versus Saturday versus Sunday). The source of the underlying profiles was either MOVES or VTRIS data (see Figure 3-21). The states individual profiles were averaged together to create a new default profile[26]. Figure 3-22 shows two new national default profiles for light duty gas vehicles (LDGV, SCC6 220121) and combination long-haul diesel trucks (HHDDV, SCC6 220262) on restricted urban roadways (interstates and freeways).

Figure 3-22. Updated national default profiles for LDGV vs. HHDDV, urban restricted

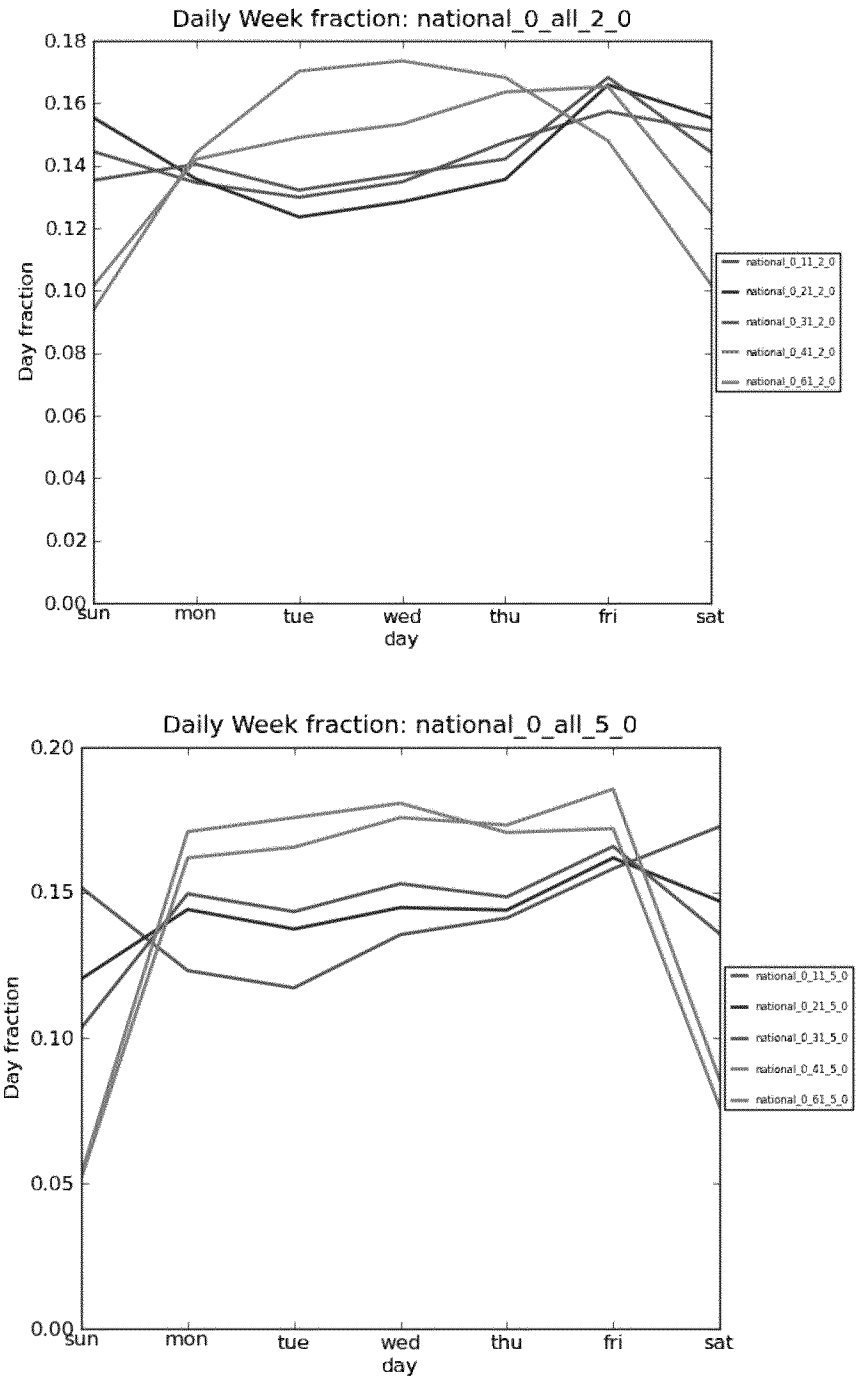




[26] Note that the states were weighted equally in the average independent of the size of the state or the variation in submitted county data.

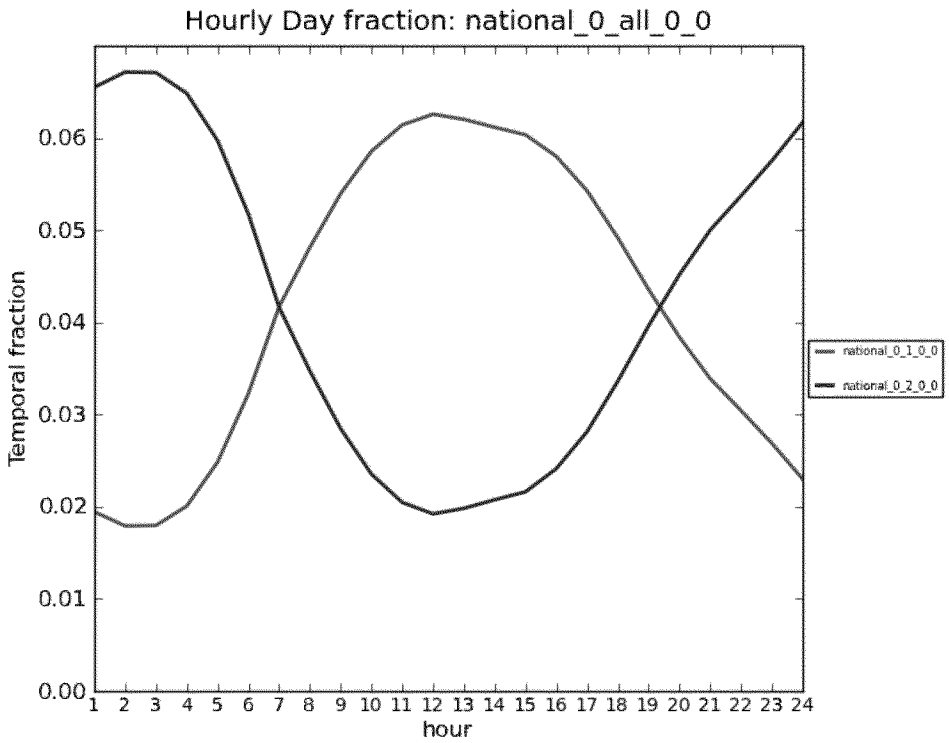
The blue lines of Figure Figure 3-22 indicate the weekday profile, the green the Saturday profile, and the red the Sunday profile. In comparison, the new default profiles for weekdays places more LDGV VMT (upper plot) in the rush hours while placing HHDDV VMT (lower plot) predominately in the middle of the day with a longer tail into the evening hours and early morning. In addition to creating diurnal profiles, the EPA developed day of week profiles using the VTRIS data. The creation of the state and national profiles was similar to the diurnal profiles (described above). Figure 3-23 shows a set of national default profiles for rural restricted roads (top plot) and urban unrestricted roads (lower plot). Each vehicle type is a different color on the plots.

Figure 3-23. Updated national default profiles for day of week



The EPA also developed a national profile for hoteling by averaging all the combination long-haul truck profiles on restricted roads (urban and rural) for weekdays to create a single national restricted profile (blue line in Figure 3-24). This was then inverted to create a profile for hoteling (green line in Figure 3-24). This single national profile was used for hoteling irrespective of location.

Figure 3-24. Combination long-haul truck restricted and hoteling profile



For California, CARB supplied diurnal profiles that varied by vehicle type, day of the week[27], and air basin. These CARB specific profiles were used in developing EPA estimates for California. Although the EPA adjusted the total emissions to match California's submittal to the 2011NEIv2, the temporalization of these emissions took into account both the state-specific VMT profiles and the SMOKE-MOVES process of incorporating meteorology. For more details on the adjustments to California's onroad emissions, see Section 2011 onroad mobile sources (onroad) and the 2011NEIv2 TSD.

3.3.7 Additional sector specific details (afdust, beis, cmv, rail, nonpt, ptnonipm, ptfire, np_oilgas)

For the afdust sector, meteorology is not used in the development of the temporal profiles, but it is used to reduce the total emissions based on meteorological conditions. These adjustments are applied through sector-specific scripts, beginning with the application of land use-based gridded transport fractions and then subsequent zero-outs for hours during which precipitation occurs or there is snow cover on the ground. The land use data used to reduce the NEI emissions explains the amount of emissions that are subject to transport. This methodology is discussed in (Pouliot et al., 2010) and in "Fugitive Dust Modeling for the 2008 Emissions Modeling Platform" (Adelman, 2012). The precipitation adjustment is

[27] California's diurnal profiles varied within the week. Monday, Friday, Saturday, and Sunday had unique profiles and Tuesday, Wednesday, Thursday had the same profile.

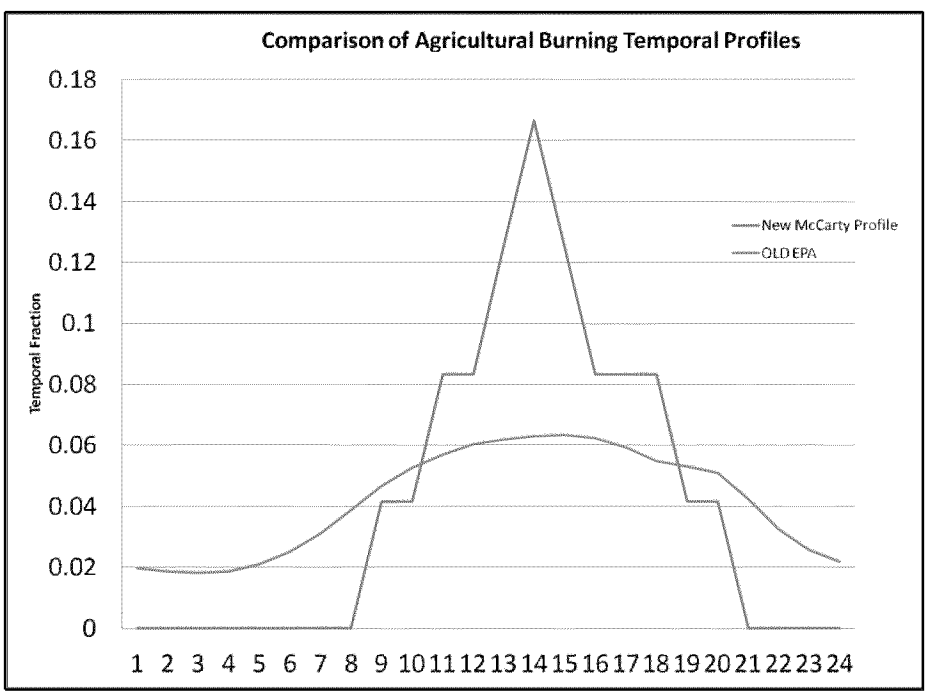
applied to remove all emissions for days where measureable rain occurs. Therefore, the afdust emissions vary day-to-day based on the precipitation and/or snow cover for that grid cell and day. Both the transport fraction and meteorological adjustments are based on the gridded resolution of the platform; therefore, somewhat different emissions will result from different grid resolutions. Application of the transport fraction and meteorological adjustments prevents the overestimation of fugitive dust impacts in the grid modeling as compared to ambient samples.

Biogenic emissions in the beis sector vary by every day of the year because they are developed using meteorological data including temperature, surface pressure, and radiation/cloud data. The emissions are computed using appropriate emission factors according to the vegetation in each model grid cell, while taking the meteorological data into account.

For the cmv and rail sectors, emissions are allocated with flat monthly and day of week profiles, and most emissions are also allocated with flat hourly profiles.

For the agfire sector, the emissions were allocated to months by adding up the available values for each day of the month. For all agricultural burning, the diurnal temporal profile used reflected the fact that burning occurs during the daylight hours - see Figure 3-25 (McCarty et al., 2009). This puts most of the emissions during the work day and suppresses the emissions during the middle of the night. A uniform profile for each day of the week was used for all agricultural burning emissions in all states, except for the following states that the EPA used state-specific day of week profiles: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, Oklahoma, and Texas.

Figure 3-25. Agricultural burning diurnal temporal profile



Updates were made to temporal profiles for the ptnonipm sector in the 2011v6.2 platform based on comments and data review by EPA staff. Temporal profiles for small airports (i.e., non-commercial) were updated to eliminate emissions between 10pm and 6am due to a lack of tower operations. Industrial process that are not likely to shut down on Sundays such as those at cement plants were assigned to other

more realistic profiles that included emissions on Sundays. This also affected emissions on holidays because Sunday emissions are also used on holidays.

The ptfire sector is used in the base year case (2011en) and in the future base case (2023en). The 2007 and earlier platforms had additional regulatory cases that used averaged fires and temporally averaged EGU emissions, but the 2011 platform uses base year-specific (i.e., 2011) data for both cases.

For the nonroad sector, while the NEI only stores the annual totals, the modeling platform uses monthly inventories from output from NMIM. For California, a monthly inventory was created from CARB's annual inventory using EPA-estimated NMIM monthly results to compute monthly ratios by pollutant and SCC7 and these ratios were applied to the CARB inventory to create a monthly inventory.

Some cross reference updates for temporalization of the np_oilgas sector were made in the 2011v6.2 and 2011v6.3 platform to assign np_oilgas sources to 24 hour per day, 7 days a week based on comments received.

3.3.8 Time zone corrections

Various time zone corrections/updates were made to the 2011v6.3 platform, which affects the hourly temporalization of emissions. Table 3-18 lists the time zone corrections for U.S. counties. Almost the entire country of Mexico needed to be corrected. Most of country is Central time zone with DST, except for the six northwesternmost states. In the 2011v6.2 platform, most of Mexico was Central time without DST. The time zone corrections made to Canada are the following:

- Quebec: Seven census divisions moved from Atlantic Time to Eastern Time. Only one Quebec census division remains in Atlantic Time zone.
- Manitoba: Daylight Saving Time (DST) added. (Only affects entire province FIPS; individual census divisions were already correct.)
- Saskatchewan: now Central time without DST; was previously a mix of Central time and Mountain Time with DST.
- Peace River, BC: changed from Pacific Time with DST to Mountain Time without DST.
- NW Territories: moved from Pacific Time to Mountain Time. (Only affects entire province FIPS; individual census divisions were already correct.)

Table 3-18. Time zone corrections for US counties in 2011v6.3 platform

FIPS	State	County	2011eh	2011ek
ALL	Indiana	ALL	some with no daylight saving time implemented (DST)	all changed to implementing DST
20093	Kansas	Kearny Co	MT	CT
21087	Kentucky	Green Co	ET	CT
21225	Kentucky	Union Co	ET	CT
21233	Kentucky	Webster Co	ET	CT
38057	North Dakota	Mercer Co	MT	CT
38059	North Dakota	Morton Co	MT	CT
38065	North Dakota	Oliver Co	MT	CT
38085	North Dakota	Sioux Co	MT	CT
46075	South Dakota	Jones Co	MT	CT
46095	South Dakota	Mellette Co	MT	CT
46121	South Dakota	Todd Co	MT	CT

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3.4 Spatial Allocation

The methods used to perform spatial allocation are summarized in this section. For the modeling platform, spatial factors are typically applied by county and SCC. As described in Emissions Modeling Overview, spatial allocation was performed for a national 12-km domain. To accomplish this, SMOKE used national 12-km spatial surrogates and a SMOKE area-to-point data file. For the U.S., the EPA updated surrogates to use circa 2010-2011 data wherever possible. For Mexico and Canada, updated spatial surrogates were used as described below. The U.S., Mexican, and Canadian 12-km surrogates cover the entire CONUS domain 12US1 shown in Figure 3-1.

The changes to spatial allocation in the 2011el platform were limited to the addition of SCCs from the MOVES-Mexico inventory to the spatial cross reference for Canada and Mexico. The 2011en platform update introduced a new set of Canadian spatial surrogates, a new shipping lanes surrogate for U.S. emissions, and a new population surrogate in Mexico. Otherwise, the exception of some updates to the spatial surrogate cross reference, the spatial surrogates for the U.S. and Mexico used in the 2011v6.3 platform are the same as the surrogates used for the 2011v6.2 platform (EPA, 2015b). The details regarding how the 2011v6.2 platform surrogates were created are available from ftp://ftp.epa.gov/EmisInventory/2011v6/v2platform/spatial_surrogates/ in the files *US_SpatialSurrogate_Workbook_v072115.xlsx* and *US_SpatialSurrogate_Documentation_v070115.pdf*, and *SurrogateTools_Scripts_2014.zip* available. The remainder of this subsection provides further detail on the origin of the data used for the spatial surrogates and the area-to-point data.

3.4.1 Spatial Surrogates for U.S. Emissions

There are more than 100 spatial surrogates available for spatially allocating U.S. county-level emissions to the 12-km grid cells used by the air quality model. Table 3-19 lists the codes and descriptions of the surrogates. Surrogate names and codes listed in *italics* are not directly assigned to any sources for the 2011v6.3 platform, but they are sometimes used to gapfill other surrogates, or as an input for merging two surrogates to create a new surrogate that is used.

Many surrogates use circa 2010-based data, including: 2010 census data at the block group level; 2010 American Community Survey Data for heating fuels; 2010 TIGER/Line data for railroads and roads; the 2006 National Land Cover Database; 2011 gas station and dry cleaner data; and the 2012 National Transportation Atlas Data for rail-lines, ports and navigable waterways. The surrogate for ports (820) was developed based on the shapefile Ports_2014NEI while the Shipping Lane surrogate (808) was based on the Shapefile CMV_2013_Vessel_Density_CONUS1km based on 2013 shipping data from http://marinecdastre.gov. This data set included shipping lane data in the Atlantic, Pacific, Great Lakes and the Gulf of Mexico. The creation of surrogates and shapefiles for the U.S. was generated via the Surrogate Tool. The tool and documentation for it is available at https://www.cmascenter.org/sa-tools/documentation/4.2/SurrogateToolUserGuide_4_2.pdf.

Table 3-19. U.S. Surrogates available for the 2011 modeling platform.

Code	Surrogate Description	Code	Surrogate Description
N/A	Area-to-point approach (see 3.3.1.2)	507	Heavy Light Construction Industrial Land
100	Population	510	Commercial plus Industrial
110	*Housing*	515	Commercial plus Institutional Land

Code	Surrogate Description	Code	Surrogate Description
120	*Urban Population*	520	Commercial plus Industrial plus Institutional
130	Rural Population	*525*	*Golf Courses + Institutional +Industrial + Commercial*
137	*Housing Change*	526	Residential Non-Institutional
140	Housing Change and Population	527	Single Family Residential
150	Residential Heating - Natural Gas	*530*	*Residential - High Density*
160	*Residential Heating – Wood*	535	Residential + Commercial + Industrial + Institutional + Government
165	0.5 Residential Heating - Wood plus 0.5 Low Intensity Residential	540	Retail Trade
170	Residential Heating - Distillate Oil	545	Personal Repair
180	Residential Heating – Coal	*550*	*Retail Trade plus Personal Repair*
190	Residential Heating - LP Gas	555	Professional/Technical plus General Government
200	Urban Primary Road Miles	560	Hospitals
205	Extended Idle Locations	*565*	*Medical Offices/Clinics*
210	Rural Primary Road Miles	*570*	*Heavy and High Tech Industrial*
220	*Urban Secondary Road Miles*	575	Light and High Tech Industrial
221	Urban Unrestricted Roads	580	Food, Drug, Chemical Industrial
230	*Rural Secondary Road Miles*	585	Metals and Minerals Industrial
231	Rural Unrestricted Roads	590	Heavy Industrial
240	Total Road Miles	595	Light Industrial
250	Urban Primary plus Rural Primary	*596*	*Industrial plus Institutional plus Hospitals*
255	*0.75 Total Roadway Miles plus 0.25 Population*	600	Gas Stations
256	Off-Network Short-Haul Trucks	650	Refineries and Tank Farms
257	Off-Network Long-Haul Trucks	675	Refineries and Tank Farms and Gas Stations
258	Intercity Bus Terminals	680	Oil & Gas Wells circa 2005 (replaced by newer surrogates in Table 3-21. **Spatial Surrogates for Oil and Gas Sources**)
259	Transit Bus Terminals	710	Airport Points
260	Total Railroad Miles	711	Airport Areas
261	NTAD Total Railroad Density	*720*	*Military Airports*
270	*Class 1 Railroad Miles*	*800*	*Marine Ports*
271	NTAD Class 1, 2, 3 Railroad Density	*801*	*NEI Ports*
280	Class 2 and 3 Railroad Miles	*802*	*NEI Shipping Lanes*
300	Low Intensity Residential	806	Offshore Shipping NEI NOx
310	Total Agriculture	*807*	*Navigable Waterway Miles*
312	Orchards/Vineyards	808	2013 Shipping Density
320	Forest Land	*810*	*Navigable Waterway Activity*

Code	Surrogate Description	Code	Surrogate Description
330	Strip Mines/Quarries	*812*	*Midwest Shipping Lanes*
340	*Land*	820	Ports NEI2014 Activity
350	Water	850	Golf Courses
400	Rural Land Area	860	Mines
500	Commercial Land	870	Wastewater Treatment Facilities
505	Industrial Land	880	Drycleaners
506	Education	890	Commercial Timber

For the onroad sector, the on-network (RPD) emissions were spatially allocated to roadways. The refueling emissions were spatially allocated to gas station locations (surrogate 600). On-network (i.e., on-roadway) mobile source emissions were assigned to the following surrogates: rural restricted access to rural primary road miles (210); rural unrestricted access to 231; urban restricted access to urban primary road miles (200); and urban unrestricted access to 221. Off-network (RPP and RPV) emissions were spatially allocated according to the mapping in Table 3-20. Starting with the 2011v6.2 platform, emissions from the extended (i.e., overnight) idling of trucks were assigned to a new surrogate 205 that is based on locations of overnight truck parking spaces.

Table 3-20. Off-Network Mobile Source Surrogates

Source type	Source Type name	Surrogate ID
11	Motorcycle	535
21	Passenger Car	535
31	Passenger Truck	535
32	Light Commercial Truck	510
41	Intercity Bus	258
42	Transit Bus	259
43	School Bus	506
51	Refuse Truck	507
52	Single Unit Short-haul Truck	256
53	Single Unit Long-haul Truck	257
54	Motor Home	526
61	Combination Short-haul Truck	256
62	Combination Long-haul Truck	257

For the oil and gas sources in the np_oilgas sector, the spatial surrogates were updated to those shown in Table **3-21** using 2011 data consistent with what was used to develop the 2011NEI nonpoint oil and gas emissions. Note that the "Oil & Gas Wells, IHS Energy, Inc. and USGS" (680) is older and based on circa-2005 data. These surrogates were based on the same GIS data of well locations and related attributes as was used to develop the 2011NEIv2 data for the oil and gas sector. The data sources include Drilling Info (DI) Desktop's HPDI database (Drilling Info, 2012) aggregated to grid cell levels, along with data from Oil and Gas Commission (OGC) websites. Well completion data from HPDI was supplemented by implementing the methodology for counting oil and gas well completions developed for the U.S. National Greenhouse Gas Inventory. Under that methodology, both completion date and date of first production from HPDI were used to identify wells completed during 2011. In total, over 1.08 million

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unique well locations were compiled from the various data sources. The well locations cover 33 states and 1,193 counties (ERG, 2014b).

Table 3-21. Spatial Surrogates for Oil and Gas Sources

Surrogate Code	Surrogate Description
681	Spud count - Oil Wells
682	Spud count - Horizontally-drilled wells
683	Produced Water at all wells
684	Completions at Gas and CBM Wells
685	Completions at Oil Wells
686	Completions at all wells
687	Feet drilled at all wells
688	Spud count - Gas and CBM Wells
689	Gas production at all wells
692	Spud count - All Wells
693	Well count - all wells
694	Oil production at oil wells
695	Well count - oil wells
697	Oil production at Gas and CBM Wells
698	Well counts - Gas and CBM Wells

Some spatial surrogate cross reference updates were made between the 2011v6.2 platform and the 2011v6.3 platform aside from the reworking of the onroad mobile source surrogates described above. These updates included the following:

- Nonroad SCCs using spatial surrogate 525 (50 percent commercial + industrial + institutional, 50 percent golf courses) were changed to 520 (100 percent commercial + industrial + institutional). The golf course surrogate 850, upon which 525 is partially based, is incomplete and subject to hot spots;
- Some nonroad SCCs for commercial equipment in New York County had assignments updated to surrogate 340;
- Commercial lawn and garden equipment was updated to use surrogate 520; and
- Some county-specific assignments for residential wood combustion (RWC) were updated to use surrogate 300.

For the 2011en update to the 2011v6.3 platform, the CMV underway emissions were changed to use surrogate 808. RWC fireplaces in all counties, and other RWC emissions in select counties, were changed to use surrogate 300.

Not all of the available surrogates are used to spatially allocate sources in the modeling platform; that is, some surrogates shown in Table 3-19 were not assigned to any SCCs, although many of the "unused" surrogates are actually used to "gap fill" other surrogates that are used. When the source data for a surrogate has no values for a particular county, gap filling is used to provide values for the surrogate in those counties to ensure that no emissions are dropped when the spatial surrogates are applied to the

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emission inventories. Table 3-22 shows the CAP emissions (i.e., ammonia (NH_3), NOx, $PM_{2.5}$, SO_2, and VOC) by sector, with rows for each sector listed in order of most emissions to least CAP emissions.

Table 3-22. Selected 2011en CAP emissions by sector for U.S. Surrogates*

Sector	ID	Description	NH3	NOX	PM2_5	SO2	VOC
afdust	130	Rural Population	0	0	1,089,422	0	0
afdust	140	Housing Change and Population	0	0	159,485	0	0
afdust	240	Total Road Miles	0	0	286,188	0	0
afdust	310	Total Agriculture	0	0	895,786	0	0
afdust	330	Strip Mines/Quarries	0	0	58,959	0	0
afdust	400	Rural Land Area	0	0	1	0	0
ag	310	Total Agriculture	3,502,246	0	0	0	0
agfire	310	Total Agriculture	3,287	45,594	100,174	17,001	79,615
agfire	312	Orchards/Vineyards	27	432	1,082	753	799
agfire	320	Forest Land	7	8	121	0	124
cmv_c1c2	808	2013 Shipping Density	332	510,868	16,326	7,352	12,309
cmv_c1c2	820	Ports NEI2011 NOx	23	61,823	2,072	2,354	1,883
nonpt	100	Population	4,137	0	0	0	1,196,465
nonpt	140	Housing Change and Population	3	23,423	65,897	29	134,887
nonpt	150	Residential Heating - Natural Gas	40,775	217,560	4,785	1,443	12,660
nonpt	170	Residential Heating - Distillate Oil	2,045	40,842	4,523	88,432	1,394
nonpt	180	Residential Heating - Coal	247	1,033	605	7,931	1,233
nonpt	190	Residential Heating - LP Gas	136	38,705	224	705	1,432
nonpt	240	Total Road Miles	0	27	602	0	32,152
nonpt	250	Urban Primary plus Rural Primary	0	0	0	0	102,207
nonpt	260	Total Railroad Miles	0	0	0	0	2,195
nonpt	300	Low Intensity Residential	3,847	18,334	90,706	3,048	40,003
nonpt	310	Total Agriculture	0	0	614	0	363,385
nonpt	312	Orchards/Vineyards	0	441	117	1,806	262
nonpt	320	Forest Land	0	85	287	0	97
nonpt	330	Strip Mines/Quarries	0	4	0	0	48
nonpt	400	Rural Land Area	2,855	0	0	0	0
nonpt	500	Commercial Land	2,367	2	85,404	585	26,183
nonpt	505	Industrial Land	35,360	195,282	124,150	112,016	114,391
nonpt	510	Commercial plus Industrial	4	178	27	109	224,110
nonpt	515	Commercial plus Institutional Land	1,408	177,903	18,637	58,798	21,710
nonpt	520	Commercial plus Industrial plus Institutional	0	0	0	0	14,965
nonpt	527	Single Family Residential	0	0	0	0	153,528
nonpt	535	Residential + Commercial + Industrial + Institutional + Government	23	366	1,283	0	327,986
nonpt	540	Retail Trade (COM1)	0	0	0	0	1,371
nonpt	545	Personal Repair (COM3)	0	0	93	0	60,289
nonpt	555	Professional/Technical (COM4) plus General Government (GOV1)	0	0	0	0	2,865

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Sector	ID	Description	NH3	NOX	PM2_5	SO2	VOC
nonpt	560	Hospital (COM6)	0	0	0	0	10
nonpt	575	Light and High Tech Industrial (IND2 + IND5)	0	0	0	0	2,538
nonpt	580	Food, Drug, Chemical Industrial (IND3)	0	610	313	171	10,535
nonpt	585	Metals and Minerals Industrial (IND4)	0	23	140	8	443
nonpt	590	Heavy Industrial (IND1)	10	4,373	5,419	1,131	138,575
nonpt	595	Light Industrial (IND2)	0	1	244	0	79,169
nonpt	600	Gas Stations	0	0	0	0	416,448
nonpt	650	Refineries and Tank Farms	0	0	0	0	129,221
nonpt	675	Refineries and Tank Farms and Gas Stations	0	0	0	0	1,203
nonpt	711	Airport Areas	0	0	0	0	1,956
nonpt	801	Port Areas	0	0	0	0	12,469
nonpt	870	Wastewater Treatment Facilities	1,003	0	0	0	4,671
nonpt	880	Drycleaners	0	0	0	0	7,053
nonroad	100	Population	40	39,475	2,824	85	5,030
nonroad	140	Housing Change and Population	554	537,250	45,058	1,255	78,526
nonroad	261	NTAD Total Railroad Density	2	2,673	310	5	568
nonroad	300	Low Intensity Residential	106	26,637	4,324	138	202,928
nonroad	310	Total Agriculture	481	488,224	39,037	910	57,473
nonroad	350	Water	213	143,096	12,395	337	614,637
nonroad	400	Rural Land Area	157	25,658	16,711	194	620,786
nonroad	505	Industrial Land	452	146,871	5,809	411	32,978
nonroad	510	Commercial plus Industrial	382	131,572	9,888	348	139,291
nonroad	520	Commercial plus Industrial plus Institutional	205	70,541	16,361	288	255,836
nonroad	850	Golf Courses	12	2,394	112	17	7,092
nonroad	860	Mines	2	2,931	341	5	594
nonroad	890	Commercial Timber	19	12,979	1,486	38	8,680
np_oilgas	400	Rural Land Area	0	0	0	0	50
np_oilgas	680	Oil and Gas Wells	0	10	0	0	55
np_oilgas	681	Spud count - Oil Wells	0	0	0	0	6,700
np_oilgas	682	Spud count - Horizontally-drilled wells	0	5,526	208	9	349
np_oilgas	683	Produced Water at all wells	0	0	0	0	44,772
np_oilgas	684	Completions at Gas and CBM Wells	0	2,579	46	434	11,706
np_oilgas	685	Completions at Oil Wells	0	360	11	376	28,194
np_oilgas	686	Completions at all wells	0	45,044	1,742	106	101,803
np_oilgas	687	Feet drilled at all wells	0	44,820	1,449	119	9,714
np_oilgas	688	Spud count - Gas and CBM Wells	0	0	0	0	11,322
np_oilgas	689	Gas production at all wells	0	39,184	2,318	224	64,828
np_oilgas	692	Spud count - all wells	0	30,138	445	502	4,598
np_oilgas	693	Well count - all wells	0	23,437	436	93	48,205
np_oilgas	694	Oil production at oil wells	0	2,332	0	12,602	729,483
np_oilgas	695	Well count - oil wells	0	96,244	3,067	88	431,306
np_oilgas	697	Oil production at gas and CBM wells	0	3,579	183	34	465,478

Sector	ID	Description	NH3	NOX	PM2_5	SO2	VOC
np_oilgas	698	Well count - gas and CBM wells	0	373,808	6,428	2,644	525,201
onroad	200	Urban Primary Road Miles	27,650	972,477	36,555	5,698	166,352
onroad	205	Extended Idle Locations	792	287,139	6,085	102	68,756
onroad	210	Rural Primary Road Miles	12,380	812,492	24,653	2,665	81,013
onroad	221	Urban Unrestricted Roads	49,327	1,574,451	64,354	12,078	429,908
onroad	231	Rural Unrestricted Roads	30,711	1,271,368	42,148	6,577	232,468
onroad	256	Off-Network Short-Haul Trucks	0	13,769	305	13	17,456
onroad	257	Off-Network Long-Haul Trucks	0	458	38	2	1,421
onroad	258	Intercity Bus Terminals	0	168	3	0	39
onroad	259	Transit Bus Terminals	0	43	4	0	123
onroad	506	Education	0	633	31	1	1,037
onroad	507	Heavy Light Construction Industrial Land	0	558	10	0	157
onroad	510	Commercial plus Industrial	0	121,163	2,001	131	195,186
onroad	526	Residential - Non-Institutional	0	658	18	1	2,122
onroad	535	Residential + Commercial + Industrial + Institutional + Government	0	652,562	12,720	927	1,319,131
onroad	600	Gas Stations	0	0	0	0	198,012
rail	261	NTAD Total Railroad Density	2	16,536	379	260	925
rail	271	NTAD Class 1 2 3 Railroad Density	332	732,956	22,636	7,390	38,304
rail	280	Class 2 and 3 Railroad Miles	13	41,886	948	287	1,622
rwc	165	0.5 Residential Heating - Wood plus 0.5 Low Intensity Residential	15,162	27,530	318,442	7,900	385,325
rwc	300	Low Intensity Residential	4,520	6,883	62,481	1,049	56,858

3.4.2 Allocation Method for Airport-related Sources in the U.S.

There are numerous airport-related emission sources in the NEI, such as aircraft, airport ground support equipment, and jet refueling. The modeling platform includes the aircraft and airport ground support equipment emissions as point sources. For the modeling platform, the EPA used the SMOKE "area-to-point" approach for only jet refueling in the nonpt sector. The following SCCs use this approach: 2501080050 and 2501080100 (petroleum storage at airports), and 2810040000 (aircraft/rocket engine firing and testing). The ARTOPNT approach is described in detail in the 2002 platform documentation: http://www3.epa.gov/scram001/reports/Emissions%20TSD%20Vol1_02-28-08.pdf. The ARTOPNT file that lists the nonpoint sources to locate using point data were unchanged from the 2005-based platform.

3.4.3 Surrogates for Canada and Mexico Emission Inventories

The surrogates for Canada to spatially allocate the 2013 Canadian emissions have been updated in the 2011en platform. The spatial surrogate data came from Environment Canada, along with cross references. The surrogates they provided were outputs from the Surrogate Tool (previously referenced). The Canadian surrogates used for this platform are listed in Table 3-23. Surrogates for Mexico are circa 1999 and 2000 and were based on data obtained from the Sistema Municpal de Bases de Datos (SIMBAD) de INEGI and the Bases de datos del Censo Economico 1999. Most of the CAPs allocated to the Mexico and Canada surrogates are shown in Table 3-24. The emissions in this table are from the othar, othon, and othafdust sectors.

Table 3-23. Canadian Spatial Surrogates based on 2013 Inventory

Code	Canadian Surrogate Description	Code	Description
100	Population	941	PAVED ROADS
101	total dwelling	942	UNPAVED ROADS
106	ALL_INDUST	945	Commercial Marine Vessels
113	Forestry and logging	950	Combination of Forest and Dwelling
115	Agriculture and forestry activities	955	UNPAVED_ROADS_AND_TRAILS
200	Urban Primary Road Miles	960	TOTBEEF
210	Rural Primary Road Miles	965	TOTBEEF_CD
212	Mining except oil and gas	966	TOTPOUL_CD
220	Urban Secondary Road Miles	967	TOTSWIN_CD
221	Total Mining	968	TOTFERT_CD
222	Utilities	970	TOTPOUL
230	Rural Secondary Road Miles	980	TOTSWIN
240	Total Road Miles	990	TOTFERT
308	Food manufacturing	996	urban_area
321	Wood product manufacturing	1211	Oil and Gas Extraction
323	Printing and related support activities	1212	OilSands
324	Petroleum and coal products manufacturing	1251	OFFR_TOTFERT
326	Plastics and rubber products manufacturing	1252	OFFR_MINES
327	Non-metallic mineral product manufacturing	1253	OFFR Other Construction not Urban
331	Primary Metal Manufacturing	1254	OFFR Commercial Services
412	Petroleum product wholesaler-distributors	1255	OFFR Oil Sands Mines
416	Building material and supplies wholesaler-distributors	1256	OFFR Wood industries CANVEC
448	clothing and clothing accessories stores	1257	OFFR Unpaved Roads Rural
562	Waste management and remediation services	1258	OFFR_Utilities
921	Commercial Fuel Combustion	1259	OFFR total dwelling
923	TOTAL INSTITUTIONAL AND GOVERNEMNT	1260	OFFR_water
924	Primary Industry	1261	OFFR_ALL_INDUST
925	Manufacturing and Assembly	1262	OFFR Oil and Gas Extraction
926	Distribtution and Retail (no petroleum)	1263	OFFR_ALLROADS
927	Commercial Services	1264	OFFR_OTHERJET
931	OTHERJET	1265	OFFR_CANRAIL
932	CANRAIL		

Table 3-24. CAPs Allocated to Mexican and Canadian Spatial Surrogates for 2011en

Code	Mexican or Canadian Surrogate Description	NH_3	NO_X	$PM_{2.5}$	SO_2	VOC
11	MEX 2015 Population	22,095	94,828	3,784	405	121,164
14	MEX Residential Heating - Wood	0	1,010	12,952	155	89,053
16	MEX Residential Heating - Distillate Oil	0	11	0	3	0
20	MEX Residential Heating - LP Gas	0	5,042	152	0	86
22	MEX Total Road Miles	2,154	306,924	8,198	4,305	68,105
24	MEX Total Railroads Miles	0	18,710	418	164	729

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Code	Mexican or Canadian Surrogate Description	NH_3	NO_X	PM_{2_5}	SO_2	VOC
26	MEX Total Agriculture	146,737	105,222	22,250	5,106	8,400
32	MEX Commercial Land	0	61	1,343	0	19,436
34	MEX Industrial Land	3	1,055	1,626	0	98,577
36	MEX Commercial plus Industrial Land	0	1,559	26	4	83,144
38	MEX Commercial plus Institutional Land	2	1,427	64	3	42
40	MEX Residential (RES1-4)+Comercial+Industrial+Institutional+Government	0	4	9	0	63,022
42	MEX Personal Repair (COM3)	0	0	0	0	4,637
44	MEX Airports Area	0	2,521	68	319	796
46	MEX Marine Ports	0	8,291	526	4,150	84
50	MEX Mobile sources - Border Crossing - Mexico	4	136	1	2	252
100	CAN Population	593	50	585	11	263
101	CAN total dwelling	272	25,281	1,881	2,447	113,352
106	CAN ALL_INDUST	0	0	6,828	0	70
113	CAN Forestry and logging	268	1,693	0	77	5,056
115	CAN Agriculture and forestry activities	15	180	905	4	504
200	CAN Urban Primary Road Miles	1,460	65,668	2,918	261	8,929
210	CAN Rural Primary Road Miles	572	39,595	1,597	104	3,819
212	CAN Mining except oil and gas	0	0	2,108	0	0
220	CAN Urban Secondary Road Miles	2,713	98,357	5,484	553	21,628
221	CAN Total Mining	0	0	34,755	0	0
222	CAN Utilities	56	8,298	31,963	2,969	175
230	CAN Rural Secondary Road Miles	1,551	70,821	3,091	286	10,313
240	CAN Total Road Miles	31	58,110	2,036	66	93,692
308	CAN Food manufacturing	0	0	8,783	0	5,563
321	CAN Wood product manufacturing	182	1,613	0	85	5,802
323	CAN Printing and related support activities	0	0	0	0	10,739
324	CAN Petroleum and coal products manufacturing	0	529	645	238	2,268
326	CAN Plastics and rubber products manufacturing	0	0	0	0	16,066
327	CAN Non-metallic mineral product manufacturing	0	0	5,213	0	0
331	CAN Primary Metal Manufacturing	0	140	5,183	45	72
412	CAN Petroleum product wholesaler-distributors	0	0	0	0	29,688
448	CAN clothing and clothing accessories stores	0	0	0	0	81
562	CAN Waste management and remediation services	182	1,384	1,755	2,166	13,644
921	CAN Commercial Fuel Combustion	132	18,212	1,741	1,814	856
923	CAN TOTAL INSTITUTIONAL AND GOVERNEMNT	0	0	0	0	10,964
924	CAN Primary Industry	0	0	0	0	25,806
925	CAN Manufacturing and Assembly	0	0	0	0	56,437
926	CAN Distribution and Retail (no petroleum)	0	0	0	0	5,641
927	CAN Commercial Services	0	0	0	0	24,386
932	CAN CANRAIL	30	66,583	1,550	240	3,317
941	CAN PAVED ROADS	0	0	211,630	0	0
945	CAN Commercial Marine Vessels	77	63,283	2,338	14,649	3,598
950	CAN Combination of Forest and Dwelling	1,178	13,084	107,784	1,869	152,929
955	CAN UNPAVED_ROADS_AND_TRAILS	0	0	254,039	0	0
960	CAN TOTBEEF	0	0	791	0	164,199

Code	Mexican or Canadian Surrogate Description	NH_3	NO_X	PM_{2_5}	SO_2	VOC
965	CAN TOTBEEF_CD	177,624	0	0	0	0
966	CAN TOTPOUL_CD	20,316	0	0	0	0
967	CAN TOTSWIN_CD	59,387	0	0	0	0
968	CAN TOTFERT_CD	77,861	0	0	0	0
970	CAN TOTPOUL	0	0	156	0	209
980	CAN TOTSWIN	0	0	655	0	2,251
990	CAN TOTFERT	0	3,281	238,181	6,685	124
996	CAN urban_area	0	0	778	0	0
1211	CAN Oil and Gas Extraction	0	29	54,361	50	444
1212	CAN OilSands	0	0	0	0	0
1251	CAN OFFR_TOTFERT	71	77,251	5,715	52	7,079
1252	CAN OFFR_MINES	30	29,069	2,413	22	2,947
1253	CAN OFFR Other Construction not Urban	20	18,121	2,927	15	7,165
1254	CAN OFFR Commercial Services	28	14,606	1,803	23	18,293
1255	CAN OFFR Oil Sands Mines	0	0	0	0	0
1256	CAN OFFR Wood industries CANVEC	11	9,857	932	8	1,619
1257	CAN OFFR Unpaved Roads Rural	22	6,773	1,157	19	44,089
1258	CAN OFFR_Utilities	14	7,109	447	12	8,518
1259	CAN OFFR total dwelling	14	4,372	1,130	12	27,729
1260	CAN OFFR_water	2	603	93	3	5,663
1261	CAN OFFR_ALL_INDUST	3	3,671	238	3	749
1262	CAN OFFR Oil and Gas Extraction	0	509	31	0	101
1263	CAN OFFR_ALLROADS	1	931	65	1	399
1264	CAN OFFR_OTHERJET	1	781	65	1	66
1265	CAN OFFR_CANRAIL	0	65	6	0	11

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4 Development of 2023 Base-Case Emissions

The emission inventories for the future year of 2023 have been developed using projection methods that are specific to the type of emission source. Future emissions are projected from the 2011 base case either by running models to estimate future year emissions from specific types of emission sources (e.g., EGUs, and onroad and nonroad mobile sources), or for other types of sources by adjusting the base year emissions according to the best estimate of changes expected to occur in the intervening years (e.g., non-EGU point and nonpoint sources). For some sectors, the same emissions are used in the base and future years, such as biogenic and fires. For the remaining sectors, rules and specific legal obligations that go into effect in the intervening years, along with changes in activity for the sector, are considered when possible.

Emissions inventories for neighboring countries used in our modeling are included in this platform, specifically 2011 and 2023 emissions inventories for Mexico, and 2013 and 2025 emissions inventories for Canada. The meteorological data used to create and temporalize emissions for the future year cases is held constant and represents the year 2011. With the exception of speciation profiles for mobile sources and temporal profiles for EGUs, the same ancillary data files are used to prepare the future year emissions inventories for air quality modeling as were used to prepare the 2011 base year inventories.

The approach for developing the EGU emissions **for 2023en** is described in Section 4.1. For 2023el, emission projections for EGUs were developed using IPM version 5.16 and are reflected in an air quality modeling-ready flat file taken from the EPA Base Case v.5.16. The NEEDS database is an important input to IPM in that contains the generation unit records used for the model plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units and has been updated for the EPA's version 5.16 power sector modeling platform. The EGU emission projections in the flat file format, the corresponding NEEDS database, and user guides and documentation are available with the information for the EPA's Power Sector Modeling Platform v.5.16 available from https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling. The projected EGU emissions for 2023el included the Final Mercury and Air Toxics (MATS) rule announced on December 21, 2011, the Cross-State Air Pollution Rule (CSAPR) issued July 6, 2011, the CSAPR Update Rule issued October 26, 2016 and the Clean Power Plan (CPP), while the 2023en emissions include the other rules but do not include the CPP.

To project future emissions for onroad and nonroad mobile sources, the EPA used MOVES2014a and NMIM, respectively. The EPA obtained future year projected emissions for these sectors by running the MOVES and NMIM models using year-specific information about fuel mixtures, activity data, and the impacts of national and state-level rules and control programs. For this platform, the mobile source emissions for 2023 were generated by using year 2023 activity data coupled with emission factors for a MOVES run for the year 2023.

For non-EGU point and nonpoint sources, projections of 2023 emissions were developed by starting with the 2011 emissions inventories and applying adjustments that represent the impact of national, state, and local rules coming into effect in the intervening years, along with the impacts of planned shutdowns, the construction of new plants, specific information provided by states, and specific legal obligations resolving alleged environmental violations, such as consent decrees. Changes in activity are considered for sectors such as oil and gas, residential wood combustion, cement kilns, livestock, aircraft, commercial marine vessels and locomotives. Efforts were made to include some regional haze and state-reported local controls as part of a larger effort to include more local control information on stationary non-EGU sources.

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The Mid-Atlantic Regional Air Management Association (MARAMA) provided projection and control data for year 2023 for most non-point and point sectors of the year 2011 inventory. The sectors affected are afdust, ag, cmv, nonpt, np_oilgas, pt_oilgas, ptnonipm, rail, rwc, and also portable fuel containers a subsector of nonpt. These MARAMA data consisted of projection and control packets used by EPA's Control Strategy Tool (CoST) and SMOKE to develop emissions for the following states: Virginia, North Carolina, New Hampshire, New York, Pennsylvania, New Jersey, West Virginia, Connecticut, Delaware, Vermont, Maine, Rhode Island, Maryland, Massachusetts, and District of Columbia. These MARAMA packets will be made available as part of the Data Files and Summaries found at https://www.epa.gov/air-emissions-modeling/2011-version-63-platform. They were developed using methods similar to those documented in the TSD Inventory Growth and Control Factors based on EPA 2011NEIv1 Emissions Modeling Platform (SRA, 2014)

The following bullets summarize the projection methods used for sources in the various sectors, while additional details and data sources are given in the following subsections and in Table 4-1.

- EGU sector (ptegu): 2023en included EGU emissions developed using an engineering analysis approach describe in Section 4.1 and did not include CPP, while 2023el used unit-specific estimates from IPM version 5.16, including CPP, CSAPR Update, CSAPR, MATS rule, Regional Haze rule, and the Cooling Water Intakes Rule.
- Non-IPM sector (ptnonipm): Closures, projection factors and percent reductions reflect comments received from the notices of data availability for the 2011, 2017, 2018, and 2023 emissions modeling platforms including closure updates from states in summer 2017, along with emission reductions due to national and local rules, control programs, plant closures, consent decrees and settlements. Projection for corn ethanol and biodiesel plants, refineries and upstream impacts take into account Annual Energy Outlook (AEO) fuel volume projections. Airport-specific terminal area forecast (TAF) data were used for aircraft to account for projected changes in landing/takeoff activity. The year represented for this sector is 2025, except that MARAMA factors for the year 2023 were used, where applicable.
- Point and nonpoint oil and gas sectors (pt_oilgas and np_oilgas): In 2023en, state projection factors were generated using historical oil and gas production data available for 2011 to 2015 from EIA and information from AEO 2017 projections to year 2023. For 2023el, regional projection factors were used (EPA, 2016b). Co-benefits of stationary engines CAP-cobenefit reductions (RICE NESHAP) and controls from New Source Performance Standards (NSPS) are reflected for select source categories. MARAMA factors for the year 2023 were used where applicable.
- Biogenic (beis): 2011 emissions are used for all future-year scenarios and are computed with the same "11g" meteorology as is used for the air quality modeling. The 2011en case included minor corrections to the BELD4.1 landuse that used as input into the BEIS3.61 modeling system.
- Fires sectors (ptfire, agfire): No growth or control – 2011 estimates are used directly.
- Agricultural sector (ag): Year 2023 projection factors for livestock estimates based on expected changes in animal population from 2005 USDA data, updated according to EPA experts in July 2012.
- Area fugitive dust sector (afdust): For livestock PM emissions, projection factors for dust categories related to livestock estimates based on expected changes in animal population. For unpaved and paved road dust, county-level VMT projections to 2023 were considered.
- Remaining Nonpoint sector (nonpt): Projection factors and percent reductions reflect comments received from the notices of data availability for the 2011, 2017, 2018, and 2023 emissions modeling platforms, along with emission reductions due to national and local rules/control programs. PFC projection factors reflecting impact of the final Mobile Source Air Toxics (MSAT2) rule. Upstream impacts from AEO fuel volume, including cellulosic ethanol plants, are reflected. The year represented for this sector is

2025, except that MARAMA factors for the year 2023 were used, where applicable. Changes in the 2023en case include the following:

- The New York VOC change from 2011en case described in Section 2.2 was carried through to 2023en.
- A new Boiler MACT packet for North Carolina was implemented: NCDAQ_CONTROL_2011v6_2_2023_BoilerMACT_POINT_051917.xlsx (This replaces MARAMA Boiler MACT controls in North Carolina used in 2023el)
- The "nonpoint offsets" MARAMA inventory included in 2023el case were not used in the 2023en case as they were deemed inappropriate for national ozone transport modeling.

- Residential Wood Combustion (rwc): Year 2023 projection factors reflect assumed growth of wood burning appliances based on sales data, equipment replacement rates and change outs. These changes include the 2-stage NSPS for Residential Wood Heaters, resulting in growth in lower-emitting stoves and a reduction in higher emitting stoves.
- Locomotive, and non-Category 3 commercial marine sector (cmv and rail): Year 2023 projection factors for Category 1 and Category 2 commercial marine and locomotives reflect final locomotive-marine controls.
- Category 3 commercial marine vessel (cmv): Base-year 2011 emissions grown and controlled to 2023, incorporating controls based on Emissions Control Area (ECA) and International Marine Organization (IMO) global NOx and SO_2 controls.
- Nonroad mobile sector (nonroad): Other than for California and Texas, this sector uses data from a run of NMIM that utilized NONROAD2008a, using future-year equipment population estimates and control programs to 2023. The inputs were either state-supplied as part of the 2011NEIv2 process or using national level inputs, with only minor updates for 2011NEIv2. Final controls from the final locomotive-marine and small spark ignition rules are included. California data for 2023 were provided by the California Air Resources Board (CARB). For Texas, the Texas Commission on Environmental Quality (TCEQ) data were projected from 2011 to 2023 using trends based on NMIM data. For the 2023en case, temporal profile updates described in Section 3.3.2 for the 2011en case were carried forward for year 2023 modeling.
- Onroad mobile (onroad): MOVES2014a-based emissions factors for year 2023 were developed using the same representative counties, state-supplied data, meteorology, and procedures as were used to produce the 2011 emission factors. See section 4.3.1.1 for details about future year activity data used in generating emissions estimates.
- Onroad emissions data for California were provided by CARB.
- Other point (othpt), nonpoint/nonroad (othar, othafdust), onroad (othon): For Canada, year 2025inventories acquired from Environment Canada were used in the 2023en case for all of these sectors. In the 2023el case, the Canadian emissions were projected from the 2010 Environment Canada inventories for the othon and for the nonroad part of the othar sectors using projection factors derived from U.S. emissions changes from 2011 to 2023 by SCC and pollutant. In the othpt sector for the 2023el case, the Canadian point sources were modified by removing any remaining EGU facilities using coal. For Mexico, the othon inventory data in both cases were based on a 2023 run of MOVES-Mexico, while othar and othpt inventory data were interpolated to 2023 between 2018 and 2025. Offshore oil platform emissions were held constant at 2011 levels.

Table 4-1 summarizes the growth and control assumptions by source type that were used to create the U.S. 2023 base-case emissions from the base year inventories. The control, closures and projection packets (i.e., data sets) used to create the 2023 future year base-case scenario inventories from the 2011 base case are provided on the EMCH website and are discussed in more detail in the sections listed in Table 4-1. These packets were

processed through CoST to create future year emission inventories. CoST is described here: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution and discussed in context to this emissions modeling platform in Section 4.2.1. The last column in Table 4-1 indicates the order of the CoST strategy used for the source/packet type. For some sectors (e.g., ptnonipm), multiple CoST strategies are needed to produce the future year inventory because the same source category may be subject to multiple projection or control packets. For example, the "Loco-marine" projection factors are applied in a second control strategy for the ptnonipm sector, while for the cmv and rail sectors, these same projection factors can be applied in the first (and only) control strategy. Thus, in Table 4-1, packets with a "1" in the CoST strategy column are applied in the first strategy, while packets with a "2" in the CoST strategy column are applied in a second strategy that is run on an intermediate inventory output from the first strategy.

The remainder of this section is organized by broad NEI sectors with further stratification by the types of packets (e.g., projection, control, closure packets) and whether emissions are projected via a stand-alone model (e.g., EGUs use the IPM model and onroad mobile uses MOVES), using CoST, or by other mechanisms. The EGU projections are discussed in Section 4.1. Non-EGU point and nonpoint sector projections (including all commercial marine vessels, locomotives and aircraft) are described in Section 4.2, along with some background on CoST. Onroad and nonroad mobile projections are discussed in Section 4.3. Finally, projections for all "other" sources, primarily outside the U.S., are described in Section 4.44. Section 5 contains summaries of the 2011 and 2023 emissions the emissions changes between the years for emissions both within and outside of the U.S.

Table 4-1. Growth and control methodologies used to create future year emissions inventories

Description of growth, control, closure data, or, new inventory	Sector(s)	Packet Type	CAPs impacted	Section(s)	CoST Strategy
Non-EGU Point (ptnonipm and pt_oilgas sectors) Growth and Control Assumptions					
Facility, unit and stack closures, primarily from the Emissions Inventory System (EIS)	ptnonipm, pt_oilgas	CLOSURE	All	4.2.2	1
"Loco-marine rule": Growth and control to years 2023 from Locomotives and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder: March, 2008	ptnonipm, cmv, rail	PROJECTION	All	4.2.3.3	2, 1
Upstream RFS2/EISA/LDGHG impacts on gas distribution, pipelines and refineries to future years	ptnonipm, pt_oilgas, nonpt	PROJECTION	All	4.2.3.4	2
AEO-based growth for industrial sources, including oil and gas regional projections	ptnonipm, pt_oilgas, nonpt, np_oilgas	PROJECTION	All	4.2.3.5	1
Aircraft growth via Itinerant (ITN) operations at airports	ptnonipm	PROJECTION	All	4.2.3.6	1
Corn Ethanol plants adjusted via AEO volume projections to 2025	ptnonipm	PROJECTION	All	4.2.3.8	1
NESHAP: Portland Cement projects. These results are from model runs associated with the NESHAP and NSPS analysis of August, 2013 and include closures and growth.	ptnonipm, nonpt	PROJECTION & new inventories for new kilns	All	4.2.3.7 & 4.2.5.4	1 & n/a
NESHAP: RICE (reciprocating internal combustion engines) with reconsideration amendments	ptnonipm, pt_oilgas, nonpt, np_oilgas	CONTROL	CO, NO_X, PM, SO_2, VOC	4.2.4.2	1
NSPS: oil and gas	pt_oilgas, np_oilgas	CONTROL	VOC	4.2.4.1	1

Description of growth, control, closure data, or, new inventory	Sector(s)	Packet Type	CAPs impacted	Section(s)	CoST Strategy
NSPS: RICE	ptnonipm, pt_oilgas, nonpt, np_oilgas	CONTROL	CO, NO_X, VOC	4.2.4.3	2
NSPS: Gas turbines	ptnonipm, pt_oilgas	CONTROL	NO_X	4.2.4.6	1
NSPS: Process heaters	ptnonipm, pt_oilgas	CONTROL	NO_X	4.2.4.7	1
Industrial/Commercial/Institutional Boiler MACT with Reconsideration Amendments + local programs	nonpt, ptnonipm, pt_oilgas	CONTROL	CO, NO_X, PM, SO_2, VOC	4.2.4.4	1
State fuel sulfur content rules for fuel oil – via 2018 NODA comments, effective only in most northeast states	nonpt, ptnonipm, pt_oilgas	CONTROL	SO_2	4.2.4.5	1
State comments: from previous platforms (including consent decrees) and NODAs	nonpt, ptnonipm, pt_oilgas	PROJECTION & CONTROL	All	4.2.3.5, 4.2.4.11	1
Commercial and Industrial Solid Waste Incineration (CISWI) revised NSPS	ptnonipm	CONTROL	SO2	4.2.4.9	1
Arizona Regional haze controls	ptnonipm	CONTROL	NO_X,SO_2	4.2.4.8	1
New biodiesel plants for year 2018	ptnonipm	new inventory	All	4.2.5.2	n/a
Nonpoint (afdust, ag, nonpt, np_oilgas and rwc sectors) Growth and Control Assumptions					
AEO-based VMT growth for paved and unpaved roads	afdust	PROJECTION	PM	4.2.3.1	1
Livestock emissions growth from year 2011 to year 2023	ag	PROJECTION	NH_3	4.2.3.2	1
Upstream RFS2/EISA/LDGHG impacts on gas distribution, pipelines and refineries to years 2018	ptnonipm, pt_oilgas, nonpt	PROJECTION	All	4.2.3.4	2
AEO-based growth: industrial sources, including oil and gas regional projections	ptnonipm, pt_oilgas, nonpt, np_oilgas	PROJECTION	All	4.2.3.5	1
NESHAP: RICE (reciprocating internal combustion engines) with reconsideration amendments	ptnonipm, pt_oilgas, nonpt, np_oilgas	CONTROL	CO, NO_X, PM, SO_2, VOC	4.2.4.2	1
NSPS: oil and gas	pt_oilgas, np_oilgas	CONTROL	VOC	4.2.4.1	1
NSPS: RICE	ptnonipm, pt_oilgas, nonpt, np_oilgas	CONTROL	CO, NO_X, VOC	4.2.4.3	2
Residential wood combustion growth and change-outs	rwc	PROJECTION	All	4.2.3.9	1
Industrial/Commercial/Institutional Boiler MACT with Reconsideration Amendments + local programs	nonpt, ptnonipm, pt_oilgas	CONTROL	CO, NO_X, PM, SO_2, VOC	4.2.4.4	1
State fuel sulfur content rules for fuel oil – via 2018 NODA comments, effective only in most northeast states	nonpt, ptnonipm, pt_oilgas	CONTROL	SO_2	4.2.4.5	1
State comments: from previous platforms (including consent decrees) and NODAs	nonpt, ptnonipm, pt_oilgas	PROJECTION & CONTROL	All	4.2.3.5, 4.2.4.11	1

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Description of growth, control, closure data, or, new inventory	Sector(s)	Packet Type	CAPs impacted	Section(s)	CoST Strategy
MSAT2 and RFS2 impacts with state comments on portable fuel container growth and control from 2011 to years 2018	nonpt	new inventory	All	4.2.5.1	n/a
New cellulosic plants in year 2018	nonpt	new inventory	All	4.2.5.3	n/a
Onroad Mobile (onroad sector) Growth and Control Assumptions All national in-force regulations are modeled. The list includes recent key mobile source regulations but is not exhaustive.					
National Onroad Rules:					
All onroad control programs finalized as of the date of the model run, including most recently:	onroad	n/a	All	4.3	n/a
Tier-3 Vehicle Emissions and Fuel Standards Program: March, 2014					
2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: October, 2012					
Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles: September, 2011					
Regulation of Fuels and Fuel Additives: Modifications to Renewable Fuel Standard Program (RFS2): December, 2010					
Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule for Model-Year 2012-2016: May, 2010					
Final Mobile Source Air Toxics Rule (MSAT2): February, 2007					
Local Onroad Programs:					
California LEVIII Program	onroad	n/a	All	4.3	n/a
Ozone Transport Commission (OTC) LEV Program: January,1995					
Inspection and Maintenance programs					
Fuel programs (also affect gasoline nonroad equipment)					
Stage II refueling control programs					
Nonroad Mobile (cmv, rail, nonroad sectors) Growth and Control Assumptions All national in-force regulations are modeled. The list includes recent key mobile source regulations but is not exhaustive.					
National Nonroad Programs:					
All nonroad control programs finalized as of the date of the model run, including most recently:	nonroad	n/a	All	4.3.2	n/a
Emissions Standards for New Nonroad Spark-Ignition Engines, Equipment, and Vessels: October, 2008					
Growth and control from Locomotives and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder: March, 2008					
Clean Air Nonroad Diesel Final Rule – Tier 4: May, 2004					
Locomotives:					
Growth and control from Locomotives and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder: March, 2008	cmv, rail ptnonipm	PROJECTION	All	4.2.3.3	1, 2
Clean Air Nonroad Diesel Final Rule – Tier 4: May, 2004	cmv, rail	n/a	All	4.3.2	n/a
Commercial Marine:					
Category 3 marine diesel engines Clean Air Act and International Maritime Organization standards: April, 2010	cmv	PROJECTION	All	4.2.3.3	1

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Description of growth, control, closure data, or, new inventory	Sector(s)	Packet Type	CAPs impacted	Section(s)	CoST Strategy
Growth and control from Locomotives and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder: March, 2008	cmv, rail, ptnonipm	PROJECTION	All	4.2.3.3	1, 2
Clean Air Nonroad Diesel Final Rule – Tier 4: May, 2004	nonroad	n/a	All	4.3.2	n/a

4.1 EGU sector projections (ptegu)

4.1.1 Engineering Analysis Estimates for 2023 Flat File

A flat file in a format that can be input to SMOKE was prepared for the 2023en case. The underlying data and calculations used in the development of this flat file, which are described below can be found in the workbook titled *Engineering_Analysis_2023_Unit_File.xlsx* available in the "Data Files and Summaries" on the 2011v6.3 platform web page https://www.epa.gov/air-emissions-modeling/2011-version-63-platform, more specifically it can be found in the FTP area ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/reports/2011en_and_2023en/. The following spreadsheets detail some of the computations described in this section are also available via FTP: *2023en_New_Unit_Capacity_Factor_Calcs.xlsx*, *2023en_Non_NOx_non_SO2_pollutants_for_eng_analysis.xlsx*, and *2023en_Generation_Surplus_Deficit_Calcs.xlsx*. The spreadsheet 2023en_egu_summer_emissions_comparison_30sep2017.xlsx provides a comparison of the 2023 summer EGU emissions with emissions in 2011 and 2016.

4.1.1.1 SO2 and NOx emissions for units reporting under Part 75 for EPA Acid Rain Program (ARP) and Cross State Air Pollution Rule (CSAPR)

EPA starts with 2016 reported, seasonal, historical emissions for each unit. This reflects the latest owner/operator reported data available at the time of EPA analysis. The emissions data for NO_x and SO_2 for units that report data to CAMD under either the Acid Rain Program (ARP) and/or the Cross-State Air Pollution Rule (CSAPR) are aggregated to the summer/ozone season period (May-September) and winter/non-ozone period (January-April and October-December).[27] Unit-level details such as plant name, unit ID, unit type, etc. are shown in columns A through F. Reported historical data for these units such as historical emissions, heat input, generation, etc. are shown in columns G through J. The 2016 historical emissions value is in column J. The projected 2023 emissions estimate is shown in column K, and reflects either the same emissions level as reported for 2016, or a modification of that value based on adjustments to the operational or pollution control status of that unit.[28] Because the 2016 data preceded implementation of certain NO_X reduction programs (e.g., CSAPR Update, Pennsylvania RACT, and Connecticut RACT), EPA made assumptions about how EGUs would adjust their operations and emissions in order to comply with such programs in 2023. With respect to the CSAPR Update, the agency made assumptions about EGU operations in steps four and five, below. CSAPR Update compliance is demonstrated through an ozone season NO_X allowance trading program, which provides flexibility for EGU owner/operators to determine their own compliance path. As such, the assumptions that EPA applies for the purpose of developing the 2023 EGU emission projection represent one reasonable compliance path, but not the only compliance path, for EGUs in CSAPR Update states. The modifications to operational or pollution control status are made due to:

1. *Retirements* - Emissions from units with upcoming confirmed retirement dates prior to 2023 are

[27] The EPA notes that historical state-level ozone season EGU NO_x emission rates are publically available and quality assured data. They are monitored using continuous emissions monitors (CEMs) data and are reported to the EPA directly by power sector sources. They are reported under Part 75 of the CAA.

[28] Based on data and changes known as of 8/11/2017.

adjusted to zero. Retirement dates are identified through a combination of sources including EIA 860, utility-announced retirements, and stakeholder feedback provided to EPA. The impact of retiring on emissions is shown in column K. These 269 retiring units are flagged in column L and noted as "Retiring" in column M.

	2016	2023
Unit X	10,000 mmBtu x .2 lb/mmBtu = 1 ton	**0 mmBtu** x .2 lb/mmBtu =**0 ton**

2. *Coal to Gas Conversion* – Emissions from units with scheduled conversion to natural gas fuel use by 2023 are adjusted to reflect reduced emission rates associated with natural gas. To reflect a given unit's conversion to gas, that unit's 2023 emission rates for NO_x are assumed to be half of its 2016 coal-fired emission rates, and the unit's SO_2 emissions rates are adjusted to zero while utilization levels are assumed to remain the same.[29] Therefore, the 2023 projected emissions for these converting units are estimated to be half of 2016 levels for NO_x, and zero for SO_2. Units expected to convert to gas are flagged using EIA 860 and stakeholder feedback. The impact of coal to gas conversion for 2023 is shown in column K, flagged in column L, and noted as "coal to gas conversion" in column M. The example below pertains to NO_x emission estimates.

	2016	2023
Unit X	10,000 mmBtu x .2 lb/mmBtu = 1 ton	10,000 mmBtu x**.1 lb/mmBtu = .5 ton**

3. *Retrofits* – Emissions from units with scheduled SCR, SNCR and/or FGD retrofits prior to 2023 are adjusted to reflect the emission rates expected with new SCR installation (.075 lb/mmBtu of NO_x), new SNCR (a 25% decrease in emission rate), and/or new FGD (0.06 lb/mmBtu of SO_2) and are assumed to operate at the same 2016 utilization levels.[30] These emission rates were multiplied by the affected unit's 2016 heat input to estimate the 2023 emission level. The impact of post-combustion control retrofits on 2023 emissions assumptions is shown in column K, flagged in column L, and noted as "New SCR", "New SNCR" or "New FGD" in column M.
For SCR:

	2016	2023
Unit X	10,000 mmBtu x .2 lb/mmBtu = 1 ton	10,000 mmBtu x**.075 lb/mmBtu = .38 ton**

For SNCR

	2016	2023
Unit X	10,000 mmBtu x .2 lbs/mmBtu = 1 ton	10,000 mmBtu * **.15 lbs/mmBtu = .75 ton**

4. *State-of-the- art combustion controls* – Emissions from units in the CSAPR update region that were operating in 2016 without state-of-the-art combustion controls were adjusted downwards to reflect assumed installation of these controls and their expected emission rate impact. EPA assumed a 2023 emission rate of 0.1549 lbs/mmBtu for units with dry bottom wall-fired boilers expected to install/upgrade combustion controls, and 0.139 lbs/mmBtu for tangentially-fired coal units expected to install upgrade combustion controls. These emission rates were multiplied by each unit's 2016 heat input to estimate its 2023 emission level. Details of EPA's assessment of state-of-the-art NO_x combustion controls and corresponding emission rates are provided in the EGU NO_x Mitigation Strategies Final Rule TSD.[31] The impact on state-of-the-art combustion controls on 2023 emission assumptions is shown in column K, flagged in column L, and noted as

[29] See NO_x Mitigation Strategy TSD available at https://www.epa.gov/sites/production/files/2017-05/documents/egu_nox_mitigation_strategies_final_rule_tsd.pdf
[30] *Ibid.*
[31] *Ibid.*

"Install state-of-the-art combustion controls" in column M. EPA identified 47 such units that it flagged as likely to receive such control upgrades.

	2016	2023
Unit X	10,000 mmBtu x .2 lb/mmBtu = 1 ton	10,000 mmBtu x**.139 lb/mmBtu = .7 ton**

5. *SCR optimization* – Emissions from units with existing SCRs in the CSAPR update region, but that operated at an emission rate greater than 0.10 lb/mmBtu in 2016, were adjusted downwards to reflect emissions when the SCR is operated to achieve a 0.10 lb/mmBtu emission rate. This emission rate was identified as achievable and regionally cost-effective under the CSAPR Update, and represents one reasonable compliance path for the purposes of this EGU projection.[32] The optimized emission rate is multiplied by 2016 heat input levels to arrive at the 2023 emissions estimate. For the 80 units affected by this adjustment, the impact on 2023 emission assumptions is shown in column K, flagged in column L, and noted as "Optimize SCR to 0.10 lb/mmBtu" in column M. Note, this assumption only applies to ozone-season NOx as that is the season in which the CSAPR Update compliance is required.

	2016	2023
Unit X	10,000 mmBtu x .2 lb/mmBtu = 1 ton	10,000 mmBtu x**.1 lb/mmBtu = .5 ton**

6. *New Units* – Emissions were adjusted up from 2016 levels of zero to reflect firm units that are under development (e.g., under construction units) greater than 25 MW that are expected to be in commercial operation by 2023. These assumed emission values for 156 new units are reflected in columns K, flagged in column L, and noted as "new unit > 25 MW" in column M". To obtain these emissions, EPA identified all new fossil-fired EGUs coming online after 2016 according to EIA Form 860 and stakeholder comments. EPA then identified the heat rate and capacity values for these units using EIA 860 and stakeholder-provided data. Next, EPA identified the 2016 average seasonal capacity factor for similar units that came online between 2011 and 2015. EPA used these seasonal capacity factors (e.g., 65% for NGCC in the summertime and 53.4% in the wintertime), the unit's capacity, the unit's heat rate, and the unit's estimated NO_x rate to estimate 2023 emissions (capacity factor × capacity × number of hours × heat rate × NO_x emission rate = NO_x emissions). The underlying data and calculations for these new unit emission estimates are available on EPA's website at the link provided in Section 1.

	2016	2023
Unit X	0 mmBtu x 0 lb/mmBtu = 0 ton	**100 MW x .65 x 8760 hours x 8000 Btu/KWh * 01 lb/mmBtu = 22 tons**

7. *Other* – EPA also made several unit-specific adjustments to 2016 emission levels to reflect forthcoming emission or emission rate requirements specified in consent decrees, BART requirements, and/or other revised permit limits. The impacts for 2023 emission assumptions are shown in column K, flagged in column L, and noted as such in column M (e.g., values of "CT RACT" mean that they were adjusted to reflect the impacts of the Connecticut Reasonably Available Control Technology (RACT) implementation).[33] EPA assumes that the the Pennsylvania RACT rule would result in units with existing SCRs operating at 0.12lb/mmBtu year-round. However, these same units are also adjusted to operate at 0.10lb/mmBtu during the ozone season in response to the CSAPR Update. Therefore, the Pennsylvania RACT does not

[32] 81 FR 74543

[33] EPA's adjustments to Connecticut EGU emissions for the purpose of representing compliance with Connecticut's RACT rule for 2023 reflect one potential compliance path, but not the only path, available under this state rule.

impact EPA's ozone-season emission assumptions for EGUs, but it does impact emission assumptions outside of the ozone season.

4.1.1.2 SO_2 and NO_x emissions for units not reporting under Part 75 for EPA ARP and CSAPR

All non-CAMD unit EGU SO_2 and NO_X emissions are taken directly from the 2011 NEI with the exception of 10 units known to be retired before 2023. These 10 units have emissions adjusted to zero. These units are Ben French (ORIS 3325 Unit 1), Chalk Cliff Cogen (ORIS 50003 Unit GEN1), Killen Station (ORIS 6031 GT1), James De Young (ORIS 1830 Unit 4), Prairie Creek (ORIS 1073 Units 1 and 2), Kennecott Power Plant (ORIS 56163 Unit 1, 2, 3), and Hutchinson Energy Center (ORIS 1248 Unit GT4).

4.1.1.3 Other pollutants

While NO_x and SO_2 are the primary pollutants of interest for the 2023 flat file when evaluating the 2008 ozone NAAQS, there are also air quality modeling inputs for other criteria pollutants including CO, NH3, PM_{10} filterable, PM_{10} primary, $PM_{2.5}$ filterable, $PM_{2.5}$ primary, PM Condensable, and VOC. For the units that do not report under CAMD programs, EPA used the 2011 NEI emission values (with the limited exceptions noted in section 2 for retirements). For units that do report data under an EPA emission program, EPA used 2011 NEI values, but made t adjustments to reflect most recent year (2016) utilization. For example, if heat input increased by 10% from 2011 to 2016 for the unit, then emissions were adjusted upwards by 10%. EPA also used source classification code (SCC)-based emission factors to adjust emissions for units that switched primary fuel between 2011 and 2016. Finally, EPA made limited modifications to emissions to reflect changes in control status. EPA flagged units that received a FGD between 2011 and 2023, for which EPA then adjusted emissions for PM_{10} and $PM_{2.5}$ based on emission rates for similarly controlled units.

4.1.1.4 Comparing future utilization and generation levels to regional load requirements

EPA analyzed and confirmed that assumed fleet operations in its emissions estimates were compatible with future load requirements by verifying that new units would provide enough generation, assuming technology-specific capacity factors, to replace the retiring generation expected to occur by 2023. EPA assessed generation adequacy at both the national level, Interconnect, and at the level of eight National Electric Reliability Council (NERC) regions.

- EPA identified the 2017 Energy Information Administration's Annual Energy Outlook (EIA AEO) growth projections from 2016 to 2023 electricity demand levels (195 TWh) from its No CPP reference case.
- Next, EPA identified the amount of retiring generation assumed in its engineering analysis (103 TWh).[34]
- EPA added these two values together (195 TWh + 103 TWh = 298 TWh) to identify the total amount of electricity generation that would need to be provided by new units assuming non-retiring units continued to collectively generate at 2016 levels.
- EPA then identified planned new capacity as that listed in EIA form 860 as "under construction", "testing", or "site prep". EPA also included other stakeholder-reported new capacity.

[34] This is *gross* generation, not *net*, and therefore slightly over-estimates the generation deficit created by retiring units. This is a conservative assumption for the analysis of determining if sufficient generation will exist to meet load.

- Using technology-specific capacity factors[35] based on past performance and IPM documentation, EPA anticipated 249 TWh from new generation already under construction. This left a remaining load of (298-249 = 49 TWh).

Primary Fuel	New Capacity (site prep, under construction, or testing phase) (MW)	Assumed Annual Capacity Factor	Annual Generation TWh
Gas (including CCs and CTs)	28,358	70%	173.9
Nuclear	4,434	90%	35.0
Other	231	10%	0.1
Petroleum	40	10%	0.04
Solar	2,840	21.6%	5.4
Wind	9,142	42.7%	34.2
Water	270	10%	0.2
Total	**45,315**		**248.9**

- EPA then identified additional expected new generation by looking at 1) "pending" and "permitted" generation from EIA 860, stakeholder comments, and data collection services which equaled 472 TWh if all constructed, and 2) applying the minimum expected continued build rate for new solar and wind forward from 2019 through 2022 (resulting in 169 TWh of additional generation).[36][37] The expected continued build rate for solar and wind was equal to the solar and wind capacities for projects that had been identified as Application Pending, Permitted, Site Preparation, Under Construction, or Testing expected to come online in 2017. These build rates are 5,851 MW of solar and 11,074 MW of wind.[38]
- EPA combined the new generation that has been either "pending" or "permitted" along with the business as usual renewable capacity growth trends to identify up to 641 TWh of additional new generation.
- The potential new generation (641 TWh) is significantly greater than the 49 TWh generation gap identified in the bullet above, suggesting that available generation would easily exceed load requirements.
- EPA repeated this analysis at the three main interconnects and at the regional levels and found similar affirmation that potential generation levels consistent with these 2023 projections would significantly exceed demand levels.
- Finally, each state's projected 2023 emissions are compared to final CSAPR Update Rule state assurance levels to verify they do not exceed those levels.

4.1.1.5 NERC Region Generation Evaluation

EPA repeated the same analysis described in the previous section for each of the NERC Regions. First, the change in demand and generation lost from retiring units was calculated for each region as shown in Table 4-2,

[35] Assumed annual capacity factors are estimates of achievable and demonstrated capacity factors and are slightly different than the capacity factors used in the analysis to determine emissions from new EGUs. The results of this analysis do not change if these capacity factors slightly different.
[36] Because of relatively short build times for solar and wind facilities, it is unlikely that units coming on line post 2019 would be listed as "under construction" in current data sets.
[37] The total amount of new RE generation assumed in the exercise is conservative relative to AEO 2017 No CPP reference Case projections regarding RE generation growth by 2023. AEO projected an additional 349 TWh, while EPA assumes just 315 TWh.
[38] For example, in 2019, there are 1,762 MW of known solar projects in the pipeline. This calculation would add an additional 4,089 MW to equal the 2017 new build rate of 5,851 MW.

then, EPA calculated the "firm" new capacity being built in each region as shown in Table 4-3. The EPA also calculated the new capacity that was classified as permitted or application pending as shown in Table 4-4 and the expected generation from the "firm" new capacity as shown in Table 4-11.

Table 4-2. Change in demand and generation lost from retiring units for each region

NERC Region	Demand 2016 (TWh)	Demand 2023 (TWh)	Demand Change 2016 to 2023 (TWh)	Demand Change (percent)	mmBtu Retiring Units	Gen from retiring units (est. *gross*) (TWh)
ERCOT	351	380	29	8%	51,847,646	6
FRCC	208	208	0	0%	95,084,124	9
MRO	217	242	25	12%	27,582,891	2
NPCC	249	237	-12	-5%	32,217,183	3
RFC	931	928	-4	0%	280,926,895	29
SERC	1,015	1,076	61	6%	262,357,655	26
SPP	214	266	51	24%	50,532,303	5
WECC	710	755	45	6%	257,222,349	24
Total	**3,896**	**4,091**	**195**	**5%**	**1,057,771,045**	**103**

Table 4-3. "Firm" new capacity being built in each region: Site Prep, Under Construction, Testing (MW)

NERC Region	Gas (CCs and CTs)	Nuclear	Other	Petroleum	Solar	Wind	Water
ERCOT	3,866		28.6		207	2,386	
FRCC	1,640		15		80		
MRO	700		0		11	280	55
NPCC	2338		24.2	24.65	160	88	1.55
RFC	13,777		83.1	1	260	1,559	6
SERC	5,153	4,434	5	14.4	1,042		127.36
SPP			0			3,164	
WECC	884		75.432		1,080	1,665	80.3
Total	**28,358**	**4,434**	**231**	**40**	**2,840**	**9,142**	**270**

Table 4-4. New capacity classified as permitted or application pending

	Permitted, Application Pending (MW)						
NERC Region	Gas (including CCs and CTs)	Nuclear	Other	Petroleum	Solar	Wind	Water
ERCOT	240	19,804	2,716	317	1,004	4,114	
FRCC		2,140		0			
MRO	200	345		3	4	3,111	
NPCC		4,861		42	16	1,007	283
RFC	775	10,721		60	141	2,972	386

SERC		4,516	4,060	13	1,825	861	141
SPP	895	687		270	239	2,347	77
WECC		5,359		525	8,462	8,156	3,875
Total	**2,110**	**48,434**	**6,776**	**1,230**	**11,690**	**22,569**	**4,763**

Table 4-5. Expected generation from the "firm" new capacity

	Generation (TWh) from "Firm Units" (Site Prep, Under Construction, Testing)						
NERC Region	**Gas (including CCs and CTs)**	**Nuclear**	**Other**	**Petroleum**	**Solar**	**Wind**	**Water**
ERCOT	24	0	0	0	0	9	0
FRCC	10	0	0	0	0	0	0
MRO	4	0	0	0	0	1	0
NPCC	14	0	0	0	0	0	0
RFC	84	0	0	0	0	6	0
SERC	32	35	0	0	2	0	0
SPP	0	0	0	0	0	12	0
WECC	5	0	0	0	2	6	0
Total	**174**	**35**	**0**	**0**	**5**	**34**	**0**

The EPA also calculated the expected generation from the "permitted" and "application pending" generation as shown in Table 4-12. The EPA then combined this information to determine the surplus or deficit of generation in each NERC region. This was calculated twice, once considering only "firm" new generation, and again including generation that has a status of permitted or application pending as shown in Table 4-7. For the latter calculation, the EPA found that only two regions, MRO and SPP, had deficits of generation. The EPA also calculated the surplus or deficit for each region as a percentage of total 2023 demand as shown in Table 4-14.

Table 4-6. Expected generation from "permitted" and "application pending" units

	Generation (TWh) from Unit Permitted, Application Pending						
NERC Region	**Gas (including CCs and CTs)**	**Nuclear**	**Other**	**Petroleum**	**Solar**	**Wind**	**Water**
ERCOT	1	121	21	0	2	15	0
FRCC	0	13	0	0	0	0	0
MRO	1	2	0	0	0	12	0
NPCC	0	30	0	0	0	4	0
RFC	4	66	0	0	0	11	0
SERC	0	28	32	0	3	3	0
SPP	4	4	0	0	0	9	0
WECC	0	33	0	0	16	31	3
Total	**10**	**297**	**53**	**1**	**22**	**84**	**4**

Table 4-7. Review of surplus or deficit generation for each region (TWh)

NERC Region	2023 Demand	Demand Change from 2016	Gen from retiring units (est. *gross*)	New Gen.from "Firm Units" (Site Prep, under Construction, and Testing)	New Gen. from Permitted and Application Pending Units	Total New Generation	Increased Demand + Retiring Gen - New Firm Generation (Surplus or Deficit)	Increased Demand + Retiring Gen - New Total Generation (Surplus or Deficit)
ERCOT	380	29	6	33	162	195	2	-160
FRCC	208	0	9	10	13	23	-2	-15
MRO	242	25	2	5	15	20	21	7
NPCC	237	-12	3	15	34	49	-24	-58
RFC	928	-4	29	91	81	172	-66	-147
SERC	1,076	61	26	69	67	135	17	-49
SPP	266	51	5	12	18	30	44	26
WECC	755	45	24	14	83	97	56	-28
Total	**4,091**	**195**	**103**	**249**	**472**	**721**	**49**	**-424**

(for the last two columns, positive numbers are deficits, negative numbers are surpluses)

Table 4-8. Surplus or deficit generation as a fraction of total demand

NERC Region	Surplus/Deficit as a fraction of total demand (firm new units only)	Surplus/Deficit as a fraction of total demand (all new units)
ERCOT	0%	-42%
FRCC	-1%	-7%
MRO	9%	3%
NPCC	-10%	-24%
RFC	-7%	-16%
SERC	2%	-5%
SPP	17%	10%
WECC	7%	-4%
Total	**1%**	**-10%**

(positive numbers are deficits; negative numbers are surpluses)

Overall, EPA found that firm new units were close to being able to fill the gap created by increased demand and units expected to retire by 2023. Considering units that are either permitted or application pending, there is a significant surplus of generation. There was however some regional variation, with MRO and SPP having generation deficits when just considering all units permitted or with applications pending.

However, as described in the previous section, there are several additional sources of generation not captured in these projects, including additional solar and wind projects. Because of shorter construction times, not all RE generation expected to be online by 2023 is in the "under construction, testing, permitting, pending, site prep" phase. But assuming that new RE capacity build continues forward at levels greater than or equal to recent years, this additional generation would fill the deficits in these regions. For example, there were 2,505 MW of wind projects in the development pipeline (Application Pending, Permitted, Site Preparation, Under Construction, or Testing) expected to come online in SPP in 2017. If that rate of development continued in 2018

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through 2022, an additional 9,519 MW of wind capacity that is not captured in this analysis would we added, resulting in an additional estimated 35.6 TWh of electricity. That generation would be sufficient to cover the 26 TWh deficit calculated for SPP. A similar dynamic in MRO would lead to an additional 3,007 MW and 11.2 TWh of generation from wind.[39]

In addition to increases in capacity, it is also possible that electricity could be transmitted from regions with surpluses to regions with deficits. The Eastern, Western, and Texas Interconnections all have generation surpluses in the tables above.

4.1.2 Connecticut Municipal Waste Combustor Reductions

The Connecticut Department of Energy and Environmental Protection provided comments on the 2011v6.3 platform NODA regarding reductions for municipal waste combustors in the state of Connecticut as a result of a MWC regulation in support of the Connecticut RACT certification (82 FR 35454, July 31, 2017; http://www.ct.gov/deep/cwp/view.asp?a=2684&q=546804). These requirements are effective as of August 2, 2017 and the resulting impacts due to a projected reduction in usage have been incorporated as shown in Table 4-9. These reductions, which are applied to all pollutants, were calculated from information found in the Revision to Connecticut's SIP (http://ct.gov/deep/lib/deep/air/ozone/ozoneplanningefforts/SouthwestConnecticutAttainmentSIPDRAFTFINAL.pdf), and include the closure of the Covanta Projects of Wallingford units. In addition, Connecticut tightened NOx emissions limits for most types of combustion equipment using a two-phased approach, with requirements for Phase 1 beginning in June, 2018 and phase 2 limits in June, 2023. The state provided some information on the Phase 1 impacts which are included in this modeling, but Phase 2 impacts were not quantified.

Table 4-9. Connecticut MWC Emission Reductions for 2023

Facility name	EIS Facility ID	EIS Unit ID	Emission Reduction (%)
Covanta Bristol, INC	588711	46157913	6.11
Covanta Bristol, INC	588711	46158013	6.11
Covanta Projects of Wallingford	589911	46137513	100
Covanta Projects of Wallingford	589911	46137613	100
Covanta Projects of Wallingford	589911	46137713	100
C R R A / Mid-Connecticut	715611	46362613	6.11
C R R A / Mid-Connecticut	715611	46362713	6.11
C R R A / Mid-Connecticut	715611	46362913	6.11
Wheelabrator Bridgeport LP	754411	46285513	36.38
Wheelabrator Bridgeport LP	754411	46285613	36.38
Wheelabrator Bridgeport LP	754411	46285713	36.38
Covanta Southeastern CT CO	754611	46284313	6.11
Covanta Southeastern CT CO	754611	46284413	6.11
Wheelabrator Lisbon INC (WM)	8501611	961813	6.11
Wheelabrator Lisbon INC (WM)	8501611	962013	6.11

[39] This may be a conservative estimate as it's based on MRO's 2017 wind build rate of 853 MW. However, in 2019, the build rate of projects in the pipeline is expected to be 2,132 MW.

4.2 Non-EGU Point and NEI Nonpoint Sector Projections

To project all U.S. non-EGU stationary sources, facility/unit closures information and growth (PROJECTION) factors and/or controls were applied to certain categories within the afdust, ag, cmv, rail, nonpt, np_oilgas, ptnonipm, pt_oilgas and rwc platform sectors. Some facility or sub-facility-level closure information was also applied to the point sources. There are also a handful of situations where new inventories were generated for sources that did not exist in the 2011 NEI (e.g., biodiesel and cellulosic plants, yet-to-be constructed cement kilns). This subsection provides details on the data and projection methods used for these sectors.

In recent platforms, the EPA has assumed that emissions growth for most industrial sources did not track with economic growth for most stationary non-IPM sources (EPA, 2006b). This "no-growth" assumption was based on an examination of historical emissions and economic data. Recently however, the EPA has received growth (and control) data from numerous states and regional planning organizations for many industrial sources, including the rapidly-changing oil and gas sector. The EPA provided a Notice of Data Availability for the 2011v6.0 emissions modeling platform and projected 2018 inventory in January, 2014 (Docket Id. No. EPA-HQ-OAR-2013-0809). The EPA requested comment on the future year growth and control assumptions used to develop the 2018 inventories. One of the most frequent comments the EPA received was to use the growth factors information that numerous states either provided or deferred to growth factors provided by broader region-level efforts. In an attempt to make the projections approach as consistent as possible across all states, the EPA decided to expand this effort to all states for some of the most-significant industrial sources (see Section 4.2.3).

Because much of the projections and controls data are developed independently from how the EPA defines its emissions modeling sectors, this section is organized primarily by the type of projections data, with secondary consideration given to the emissions modeling sector (e.g., industrial source growth factors are applicable to four emissions modeling sectors). The rest of this section is organized in the order that the EPA uses CoST in combination with other methods to produce future year inventories: 1) for point sources, apply plant (facility or sub-facility-level) closure information via CoST; 2) apply all PROJECTION packets via CoST (multiplicative factors that could cause increases or decreases); 3) apply all percent reduction-based CONTROL packets via CoST; and 4) append all other future-year inventories not generated via CoST. This organization allows consolidation of the discussion of the emissions categories that are contained in multiple sectors, because the data and approaches used across the sectors are consistent and do not need to be repeated. Sector names associated with the CoST packets are provided in parentheses.

4.2.1 Background on the Control Strategy Tool (CoST)

CoST is used to apply most non-EGU projection/growth factors, controls and facility/unit/stack-level closures to the 2011 NEI-based emissions modeling inventories to create future year inventories for the following sectors: afdust, ag, cmv, rail, nonpt, np_oilgas, ptnonipm, pt_oilgas and rwc. Information about CoST and related data sets is available from https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

CoST allows the user to apply projection (growth) factors, controls and closures at various geographic and inventory key field resolutions. Each of these CoST datasets, also called "packets" or "programs," provides the user with the ability to perform numerous quality assurance assessments as well as create SMOKE-ready future year inventories. Future year inventories are created for each emissions modeling sector via a CoST "strategy" and each strategy includes all base year 2011 inventories and applicable CoST packets. For reasons discussed later, some emissions modeling sectors require multiple CoST strategies to account for the compounding of

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control programs that impact the same type of sources. There are also available linkages to existing and user-defined control measures databases and it is up to the user to determine how control strategies are developed and applied. The EPA typically creates individual CoST packets that represent specific intended purposes (e.g., aircraft projections for airports are in a separate PROJECTION packet from residential wood combustion sales/appliance turnover-based projections). CoST uses three packet types as described below:

1. CLOSURE: Applied first in CoST. This packet can be used to zero-out (close) point source emissions at resolutions as broad as a facility to as specific as a stack. The EPA uses these types of packets for known post-2011 controls as well as information on closures provided by states on specific facilities, units or stacks. This packet type is only used in the ptnonipm and pt_oilgas sectors.
2. PROJECTION: This packet allows the user to increase or decrease emissions for virtually any geographic and/or inventory source level. Projection factors are applied as multiplicative factors to the 2011 emissions inventories prior to the application of any possible subsequent CONTROLs. A PROJECTION packet is necessary whenever emissions increase from 2011 and is also desirable when information is based more on activity assumptions rather than known control measures. The EPA uses PROJECTION packet(s) in every non-EGU modeling sector.
3. CONTROL: These packets are applied after any/all CLOSURE and PROJECTION packet entries. The user has similar level of control as PROJECTION packets regarding specificity of geographic and/or inventory source level application. Control factors are expressed as a percent reduction (0 to 100) and can be applied in addition to any pre-existing inventory control, or as a replacement control where inventory controls are first backed out prior to the application of a more-stringent replacement control.

All of these packets are stored as data sets within the Emissions Modeling Framework and use comma-delimited formats. As mentioned above, CoST first applies any/all CLOSURE information for point sources, then applies PROJECTION packet information, followed by CONTROL packets. A hierarchy is used by CoST to separately apply PROJECTION and CONTROL packets. In short, in a separate process for PROJECTION and CONTROL packets, more specific information is applied in lieu of less-specific information in ANY other packets. For example, a facility-level PROJECTION factor will be replaced by a unit-level, or facility and pollutant-level PROJECTION factor. It is important to note that this hierarchy does not apply between packet types (e.g., CONTROL packet entries are applied irrespective of PROJECTION packet hierarchies). A more specific example: a state/SCC-level PROJECTION factor will be applied before a stack/pollutant-level CONTROL factor that impacts the same inventory record. However, an inventory source that is subject to a CLOSURE packet record is removed from consideration of subsequent PROJECTION and CONTROL packets.

The implication for this hierarchy and intra-packet independence is important to understand and quality assure when creating future year strategies. For example, with consent decrees, settlements and state comments, the goal is typically to achieve a targeted reduction (from the 2011NEI) or a targeted future-year emissions value. Therefore, as encountered with this future year base case, consent decrees and state comments for specific cement kilns (expressed as CONTROL packet entries) needed to be applied instead of (not in addition to) the more general approach of the PROJECTION packet entries for cement manufacturing. By processing CoST control strategies with PROJECTION and CONTROL packets separated by the type of broad measure/program, it is possible to show actual changes from the base year inventory to the future year inventory as a result of applying each packet.

Ultimately, CoST concatenates all PROJECTION packets into one PROJECTION dataset and uses a hierarchal matching approach to assign PROJECTION factors to the inventory. For example, a packet entry with Ranking=1 will supersede all other potential inventory matches from other packets. CoST then computes the projected emissions from all PROJECTION packet matches and then performs a similar routine for all

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CONTROL packets. Therefore, when summarizing "emissions reduced" from CONTROL packets, it is important to note that these reductions are not relative to the 2011 inventory, but rather to the intermediate inventory ***after*** application of any/all PROJECTION packet matches (and CLOSURES). A subset of the more than 70 hierarchy options is shown in Table 4-10, although the fields in Table 4-10 are not necessarily named the same in CoST, but rather are similar to those in the SMOKE FF10 inventories. For example, "REGION_CD" is the county-state-county FIPS code (e.g., Harris county Texas is 48201) and "STATE" would be the 2-digit state FIPS code with three trailing zeroes (e.g., Texas is 48000). Table 4-4 includes corrections to matching hierarchy made in 2011v6.3 platform modeling. These corrections did cause emissions changes from the 2011v6.2 platform to 2011v6.3 platform for the np_oilgas, pt_oilgas, ptnonipm and nonpt sectors.

Table 4-10. Subset of CoST Packet Matching Hierarchy

Rank	Matching Hierarchy	Inventory Type
1	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID, PROCESS_ID, SCC, POLL	point
2	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID, PROCESS_ID, POLL	point
3	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID, POLL	point
4	REGION_CD, FACILITY_ID, UNIT_ID, POLL	point
5	REGION_CD, FACILITY_ID, SCC, POLL	point
6	REGION_CD, FACILITY_ID, POLL	point
7	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID, PROCESS_ID, SCC	point
8	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID, PROCESS_ID	point
9	REGION_CD, FACILITY_ID, UNIT_ID, REL_POINT_ID	point
10	REGION_CD, FACILITY_ID, UNIT_ID	point
11	REGION_CD, FACILITY_ID, SCC	point
12	REGION_CD, FACILITY_ID	point
13	REGION_CD, NAICS, SCC, POLL	point, nonpoint
14	REGION_CD, NAICS, POLL	point, nonpoint
15	STATE, NAICS, SCC, POLL	point, nonpoint
16	STATE, NAICS, POLL	point, nonpoint
17	NAICS, SCC, POLL	point, nonpoint
18	NAICS, POLL	point, nonpoint
19	REGION_CD, NAICS, SCC	point, nonpoint
20	REGION_CD, NAICS	point, nonpoint
21	STATE, NAICS, SCC	point, nonpoint
22	STATE, NAICS	point, nonpoint
23	NAICS, SCC	point, nonpoint
24	NAICS	point, nonpoint
25	REGION_CD, SCC, POLL	point, nonpoint
26	STATE, SCC, POLL	point, nonpoint
27	SCC, POLL	point, nonpoint
28	REGION_CD, SCC	point, nonpoint
29	STATE, SCC	point, nonpoint
30	SCC	point, nonpoint
31	REGION_CD, POLL	point, nonpoint
32	REGION_CD	point, nonpoint
33	STATE, POLL	point, nonpoint
34	STATE	point, nonpoint
35	POLL	point, nonpoint

The contents of the controls, local adjustments and closures for the future year base case are described in the following subsections. Year-specific projection factors (PROJECTION packets) for the future year were used to create the future year base case, unless noted otherwise in the specific subsections. The contents of a few of

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these projection packets (and control reductions) are provided in the following subsections where feasible. However, most sectors used growth or control factors that varied geographically and their contents could not be provided in the following sections (e.g., facilities and units subject to the Boiler MACT reconsideration has thousands of records). The remainder of Section 4.2 is divided into several subsections that are summarized in Table 4-5. Note that future year inventories were used rather than projection or control packets for some sources.

Table 4-11. Summary of non-EGU stationary projections subsections

Subsection	Title	Sector(s)	Brief Description
4.2.2	CoST Plant CLOSURE packet	ptnonipm, pt_oilgas	All facility/unit/stack closures information, primarily from Emissions Inventory System (EIS), but also includes information from states and other organizations.
4.2.3	CoST PROJECTION packets	All	Introduces and summarizes national impacts of all CoST PROJECTION packets to the future year.
4.2.3.1	Paved and unpaved roads VMT growth	afdust	PROJECTION packet: county-level resolution, based on VMT growth.
4.2.3.2	Livestock population growth	ag	PROJECTION packet: national, by-animal type resolution, based on animal population projections.
4.2.3.3	Locomotives	rail, ptnonipm	PROJECTION packet: Rail projections are by FIPS/SCC/poll for Calif. And SCC/poll for rest of US. NC rail projection packet was added for NODA, by FIPS/SCC/poll.
4.2.3.3	Category 1, 2, and 3 commercial marine vessels	cmv	PROJECTION packet: Category 1 & 2: CMV uses SCC/poll for all states except Calif. Category 3: region-level by-pollutant, based on cumulative growth and control impacts from rulemaking.
4.2.3.4	OTAQ upstream distribution, pipelines and refineries	nonpt, ptnonipm, pt_oilgas	PROJECTION packet: national, by-broad source category, based on upstream impacts from mobile source rulemakings.
4.2.3.5	Oil and gas and industrial source growth	nonpt, np_oilgas, ptnonipm, pt_oilgas	Several PROJECTION packets: varying geographic resolutions from state, county, to oil/gas play-level and by-process/fuel-type applications. Data derived from AEO2016 with several modifications.
4.2.3.6	Aircraft	ptnonipm	PROJECTION packet: by-airport for all direct matches to FAA Terminal Area Forecast data, with state-level factors for non-matching NEI airports.
4.2.3.7	Cement manufacturing	ptnonipm	PROJECTION packet: by-kiln projections based on Industrial Sectors Integrated Solutions (ISIS) model of demand growth and Portland Cement NESHAP.
4.2.3.8	Corn ethanol plants	ptnonipm	PROJECTION packet: national, based on 2014 AEO renewable fuel production forecast.
4.2.3.9	Residential wood combustion	rwc	PROJECTION packet: national with exceptions, based on appliance type sales growth estimates and retirement assumptions and impacts of recent NSPS.

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Subsection	Title	Sector(s)	Brief Description
4.2.4	CoST CONTROL packets	nonpt, np_oilgas, ptnonipm, pt_oilgas	Introduces and summarizes national impacts of all CoST CONTROL packets in the future year.
4.2.4.1	Oil and gas NSPS	np_oilgas, pt_oilgas	CONTROL packet: national, oil and gas NSPS impacting VOC only for some activities.
4.2.4.2	RICE NESHAP	nonpt, np_oilgas, ptnonipm, pt_oilgas	CONTROL packet: national, reflects NESHAP amendments on compression and spark ignition stationary reciprocating internal combustion engines (RICE).
4.2.4.3	RICE NSPS	nonpt, np_oilgas, ptnonipm, pt_oilgas	CONTROL packet: state and county-level new source RICE controls, whose reductions by-definition, are a function of growth factors and also equipment retirement assumptions.
4.2.4.4	ICI Boilers	nonpt, ptnonipm, pt_oilgas	CONTROL packet: by-fuel, and for point sources, by-facility-type controls impacting Industrial and Commercial/Institutional boilers from rulemaking and state-provided information.
4.2.4.5	Fuel sulfur rules	nonpt, ptnonipm, pt_oilgas	CONTROL packet: state and MSA-level fuel sulfur control programs provided by several northeastern U.S. states.
4.2.4.6	Natural gas turbines NSPS	ptnonipm, pt_oilgas	CONTROL packet: state and county-level new source natural gas turbine controls, whose reductions by-definition, are a function of growth factors and also equipment retirement assumptions.
4.2.4.7	Process heaters NSPS	ptnonipm, pt_oilgas	CONTROL packet: state and county-level new source process heaters controls, whose reductions by-definition, are a function of growth factors and also equipment retirement assumptions.
4.2.4.8	Arizona Regional Haze	ptnonipm	CONTROL packet: Regional haze controls for Arizona provided by Region 9.
4.2.4.9	CISWI	ptnonipm	CONTROL packet reflecting EPA solid waste rule cobenefits.
4.2.4.11	Data from comments on previous platforms	nonpt, ptnonipm, pt_oilgas	CONTROL packets for all other programs, including Regional Haze, consent decrees/settlements, and other information from states/other agencies in prior platforms.
4.2.5	Stand-alone future year inventories	nonpt, ptnonipm	Introduction to future-year inventories not generated via CoST strategies/packets.
4.2.5.1	Portable fuel containers	nonpt	Reflects impacts of Mobile Source Air Toxics (MSAT2) on PFCs.
4.2.5.2	Biodiesel plants	ptnonipm	Year 2018 new biodiesel plants provided by OTAQ reflecting planned sited-plants production volumes.
4.2.5.3	Cellulosic plants	nonpt	Year 2018 new cellulosic ethanol plants based on cellulosic biofuel refinery siting provided by OTAQ and 2018 NODA.

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Subsection	Title	Sector(s)	Brief Description
4.2.5.4	New cement plants	nonpt, ptnonipm	Year 2018 policy case-derived new cement kilns, permitted (point) and model-generated based on shifted capacity from some closed units to open units (nonpt)

4.2.2 CoST Plant CLOSURE Packet (ptnonipm, pt_oilgas)

Packet: "CLOSURES_2011v6_2_v5_18aug2017_nf_v1"

The CLOSURES packet contains facility, unit and stack-level closure information derived from the following sources:

1. Emissions Inventory System (EIS) facilities report from August 1, 2017 with closure status equal to "PS" (permanent shutdown);
2. input on closures provided by states in summer 2017 including Georgia, Illinois, Kansas, Michigan, Missouri, Minnesota, North Carolina, Ohio, Virginia, West Virginia, and Wisconsin;
3. concatenation of all 2011v6.0 closures information; see Section 4.2.11.3 from the 2011v6.0 platform TSD;
4. comments from states and regional planning organizations on the 2011v6.2 platform for states including Oklahoma; and
5. closures provided by MARAMA with 2011v6.3 2023 CoST packets.

The 2011v6.3 closure information is from a concatenation of previous facility and unit-level closure information used in the 2008 NEI-based emissions modeling platform used for 2007 air quality modeling. In addition, comments on the 2011v6.0 emissions modeling platform received by states and other agencies indicated that some previously specified closures should remain open. Ultimately, all data were updated to match the SMOKE FF10 inventory key fields, with all duplicates removed, and a single CoST packet was generated. The cumulative reductions in emissions for ptnonipm are shown in Table 4-12.

Table 4-12. Reductions from all facility/unit/stack-level closures for 2023en.

Pollutant	ptnonipm	pt_oilgas
CO	108,767	10,744
NH3	1,902	0
NOX	41,274	19,287
PM10	11,382	502
PM2.5	8,319	488
SO2	96,571	1,753
VOC	26,085	7,033

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4.2.3 CoST PROJECTION Packets (afdust, ag, cmv, rail, nonpt, np_oilgas, ptnonipm, pt_oilgas, rwc)

As previously discussed, for point inventories, after application of any/all CLOSURE packet information, the next step in running a CoST control strategy is the application of all CoST PROJECTION packets. Regardless of inventory type (point or nonpoint), the PROJECTION packets applied prior to the CoST packets. For several emissions modeling sectors (i.e., afdust, ag, cmv, rail and rwc), there is only one CoST PROJECTION packet. For all other sectors, there are several different sources of PROJECTIONS data and, therefore, there are multiple PROJECTION packets that are concatenated and quality-assured for duplicates and applicability to the inventories in the CoST strategy. The PROJECTION (and CONTROL) packets were separated into a few "key" control program types to allow for quick summaries of these distinct control programs. The remainder of this section is broken out by CoST packet, with the exception of discussion of the various packets used for oil and gas and industrial source projections; these packets are a mix of different sources of data that targeted similar sources.

MARAMA provided PROJECTION and CONTROL packets for year 2023 for states including: Connecticut, Delaware, Maryland, Massachusetts, New Hampshire, New York, New Jersey, North Carolina, Pennsylvania, Rhode Island, Vermont, Virginia, West Virginia, Maine, and the District of Columbia. MARAMA only provided pt_oilgas and np_oilgas packets for Rhode Island, Maryland and Massachusetts. For states not covered by the MARAMA packets, projection factors for 2023 were generated by interpolating from the 2017 and 2025 packets, except for the nonpt and ptnonipm sectors that represent 2025 levels. The 2025 CoST packets are documented in the TSD Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform (USEPA, 2015b).

4.2.3.1 Paved and unpaved roads VMT growth (afdust)

Packet:

" PROJECTION_2011el_2023el_AFDUST_VMT_CPP_19sep2016_v0.txt"
"BETA_Projections_AFDUST_2023_21jul2016_emf_csv_02sep2016_v0.txt" (MARAMA)

These packets consist of county-level VMT projection factors for paved/unpaved roads and are based on county comparison of projected year 2023 VMT versus year 2011 VMT. The method for projecting VMT to year 2023 can be found in section 4.3.

We received comments from the 2018 NODA (search for 'EPA-HQ-OAR-2013-0809' at www.regulations.gov) suggesting we grow emissions from paved and unpaved road dust as a function of VMT. The resulting national sector-total increase from year 2011 to 2023 in $PM_{2.5}$ emissions are provided in Table 4-13. Note that this packet does not impact any other sources of fugitive dust emissions in the afdust sector (e.g., no impact on construction dust, mining and quarrying, etc.).

Table 4-13. Increase in total afdust $PM_{2.5}$ emissions from VMT projections

2011 Emissions	2023 Emissions	Percent Increase in 2023
2,510,246	2,753,900	9.71%

4.2.3.2 Livestock population growth (ag)

Packet:

"PROJECTION_2011_2023_ag_2011v6_2_no_RFS2_31aug2016_v0.txt"
"BETA_Projections_AG_2023_21jul2016" (MARAMA)

The EPA estimated animal population growth in NH_3 emissions from livestock in the ag sector. Except for dairy cows and turkey production, the animal projection factors are derived from national-level animal population projections from the USDA and the Food and Agriculture Policy and Research Institute (FAPRI). This methodology was initiated in 2005 for the 2005 NEI, but was updated on July 24, 2012, in support of the 2007v5 platform (EPA, 2012). For dairy cows, the EPA assumed that there would be no growth in emissions based on little change in U.S. dairy cow populations from years 2011 through 2023, according to linear regression analyses of the FAPRI projections. This assumption was based on an analysis of historical trends in the number of such animals compared to production rates. Although productions rates have increased, the number of animals has declined. Based on this analysis, the EPA concluded that production forecasts do not provide representative estimates of the future number of cows and turkeys; therefore, these forecasts were not used for estimating future-year emissions from these animals. In particular, the dairy cow population is projected to decrease in the future as it has for the past few decades; however, milk production will be increasing over the same period. Note that the NH_3 emissions from dairies are not directly related to animal population, but also nitrogen excretion. With the cow numbers going down and the production going up, the excretion value will change, but no change was assumed because a quantitative estimate was not available.

The national projection factors by animal category and ag sector total impacts are provided in Table 4-14, while the projection factors for MARAMA states varied by state. As discussed below, dairy cows are assumed to have no growth in animal population and, therefore, the projection factor for these animals is 1.0 (no growth). Impacts from the renewable fuels mandate are not included in projections for this sector. The overall average factor was 1.037 resulting in a 2.47% increase over 2011 and total emissions of 3,609,331 tons.

Table 4-14. NH_3 projection factors and total impacts to years 2023 for animal operations

Animal Category	Projection Factors
Dairy Cow	1.000
Beef	0.978
Pork	1.106
Broilers	1.119
Turkeys	0.927
Layers	1.087
Poultry Average	1.078

4.2.3.3 Locomotives and category 1, 2, & 3 commercial marine vessels (cmv, rail, ptnonipm, othpt)

Packets for rail, cmv and ptnonipm:

"PROJECTION_2011v6_3_2023_c1c2rail_BASE_02sep2016_v0.txt"
"PROJECTION_2011_2023_C3_CMV_ECA_IMO_2011v6_3_02sep2016_v0.txt"
"BETA_Projections_C1C2RAIL_2023_21jul2016_emf_csv_02sep2016_v0.txt" (MARAMA)

There are two components used to create projection factors for year 2023. The first component of the future year cmv and rail inventories is the non-California data projected from the 2011 base case. The second component is the CARB-supplied year 2011 and 2023 data for California.

For all states outside of California, national projection factors by SCC and pollutant between 2011 and future years reflect the May 2004 "Tier 4 emissions standards and fuel requirements" (https://nepis.epa.gov/Exe/ZyPDF.cgi/P100K5U2.PDF?Dockey=P100K5U2.PDF) as well as the March 2008 "Final locomotive-marine rule" controls (https://nepis.epa.gov/Exe/ZyPDF.cgi/P100094D.PDF?Dockey=P100094D.PDF). The future-year cmv and rail emissions account for increased fuel consumption based on Energy Information Administration (EIA) fuel consumption projections for freight, and emissions reductions resulting from emissions standards from the Final Locomotive-Marine rule (EPA, 2009d)[40]. For locomotives, the EPA applied HAP factors for VOC HAPs by using VOC projection factors to obtain 1,3-butadiene, acetaldehyde, acrolein, benzene, and formaldehyde. Similar to locomotives, C1/C2 VOC HAPs were projected based on the VOC factor. C1/C2 diesel emissions were projected based on the Final Locomotive Marine rule national-level factors. These non-California projection ratios are provided in Table 4-15. Note that projection factors for "…Yard Locomotives" (SCC=2285002010) are applied to the ptnonipm (point inventory) "yard locomotives" (SCC=28500201) reported by a couple of states in the 2011 NEI. Note that the factors for MARAMA states are similar to those below, but county-specific factors were provided for North Carolina and those are not reflected in the table.

Table 4-15. Non-California projection factors for locomotives and Category 1 and Category 2 CMV Emissions

SCC	Description	Poll	2023 Factor
2280002XXX	Marine Vessels, Commercial; Diesel; Underway & port emissions	CO	0.955
2280002XXX	Marine Vessels, Commercial; Diesel; Underway & port emissions	NO_X	0.603
2280002XXX	Marine Vessels, Commercial; Diesel; Underway & port emissions	PM	0.546
2280002XXX	Marine Vessels, Commercial; Diesel; Underway & port emissions	SO_2	0.091
2280002XXX	Marine Vessels, Commercial; Diesel; Underway & port emissions	VOC	0.596
2285002006	Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	CO	1.212
2285002006	Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	NO_X	0.676
2285002006	Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	PM	0.522
2285002006	Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	SO_2	0.035
2285002006	Railroad Equipment; Diesel; Line Haul Locomotives: Class I Operations	VOC	0.486
2285002007	Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	CO	1.212
2285002007	Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	NO_X	1.062
2285002007	Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	PM	1.015
2285002007	Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	SO_2	0.035
2285002007	Railroad Equipment; Diesel; Line Haul Locomotives: Class II / III Operations	VOC	1.212
2285002008	Railroad Equipment; Diesel; Line Haul Locomotives: Passenger Trains (Amtrak)	CO	1.101
2285002008	Railroad Equipment; Diesel; Line Haul Locomotives: Passenger Trains (Amtrak)	NO_X	0.519
2285002008	Railroad Equipment; Diesel; Line Haul Locomotives: Passenger Trains (Amtrak)	PM	0.418
2285002008	Railroad Equipment; Diesel; Line Haul Locomotives: Passenger Trains (Amtrak)	SO_2	0.032
2285002008	Railroad Equipment; Diesel; Line Haul Locomotives: Passenger Trains (Amtrak)	VOC	0.356
2285002009	Railroad Equipment; Diesel; Line Haul Locomotives: Commuter Lines	CO	1.101

[40] This rule lowered diesel sulfur content and tightened emission standards for existing and new locomotives and marine diesel emissions to lower future-year PM, SO_2, and NOx, and is documented at: http://www.epa.gov/otaq/marine.htm#2008final.

SCC	Description	Poll	2023 Factor
2285002009	Railroad Equipment; Diesel; Line Haul Locomotives: Commuter Lines	NO_X	0.519
2285002009	Railroad Equipment; Diesel; Line Haul Locomotives: Commuter Lines	PM	0.418
2285002009	Railroad Equipment; Diesel; Line Haul Locomotives: Commuter Lines	SO_2	0.032
2285002009	Railroad Equipment; Diesel; Line Haul Locomotives: Commuter Lines	VOC	0.356
2285002010	Railroad Equipment; Diesel; Yard Locomotives	CO	1.212
2285002010	Railroad Equipment; Diesel; Yard Locomotives	NO_X	0.873
2285002010	Railroad Equipment; Diesel; Yard Locomotives	PM	0.845
2285002010	Railroad Equipment; Diesel; Yard Locomotives	SO_2	0.035
2285002010	Railroad Equipment; Diesel; Yard Locomotives	VOC	0.812

For California projections, the CARB provided to the EPA the locomotive, and C1/C2 commercial marine emissions used to reflect years 2011 and 2023. These CARB inventories included nonroad rules reflected in the December 2010 Rulemaking Inventory (http://www.arb.ca.gov/regact/2010/offroadlsi10/offroadisor.pdf), those in the March 2011 Rule Inventory, the Off-Road Construction Rule Inventory for "In-Use Diesel," cargo handling equipment rules in place as of 2011 (see http://www.arb.ca.gov/ports/cargo/cargo.htm), and the 2007 and 2010 regulations to reduce emissions diesel engines on commercial harbor craft operated within California waters and 24 nautical miles (nm) of the California baseline.

The California C1/C2 CMV and locomotive year-specific 2023 emissions were obtained from the CARB in the form of Excel workbooks. These data were converted to SMOKE FF10 format. These emissions were developed using Version 1 of the CEPAM, which supports various California off-road regulations. Documentation of the CARB off-road methodology, including cmv and rail sector data, is provided here: http://www.arb.ca.gov/msei/categories.htm#offroad_motor_vehicles.

The non-California projection factors were applied to all "offshore" C1 and C2 CMV emissions. These offshore emissions, in the 2011 NEI, start at the end of state waters and extend out to the EEZ. A summary of the national impact for the U.S. (including California) and rail and offshore C1 &C2 cmv sector emissions are provided in Table 4-16.

Table 4-16. Difference in Category 1& 2 cmv and rail sector emissions between 2011en and 2023en

Region	Pollutant	2011	2023	Difference 2023 – 2011
U.S. CMV	CO	70,408	76,265	5,857
U.S. CMV	NO_X	413,314	280,626	-132,688
U.S. CMV	PM_{10}	19,629	7,513	-12,116
U.S. CMV	$PM_{2.5}$	18,099	7,039	-11,060
U.S. CMV	SO_2	91,045	6,811	-84,234
U.S. CMV	VOC	12,578	12,880	302
Offshore CMV	CO	66,395	63,421	-2,974
Offshore CMV	NO_X	326,631	197,021	-129,610
Offshore CMV	PM_{10}	10,795	5,894	-4,901
Offshore CMV	$PM_{2.5}$	10,471	5,717	-4,754
Offshore CMV	SO_2	4,014	366	-3,648

Offshore CMV	VOC	7,472	4,453	-3,019
U.S. rail	CO	122,703	145,627	22,924
U.S. rail	NO_X	791,381	563,382	-227,999
U.S. rail	PM_{10}	25,898	14,236	-11,662
U.S. rail	$PM_{2.5}$	23,963	13,165	-10,798
U.S. rail	SO_2	7,936	340	-7,596
U.S. rail	VOC	40,851	21,384	-19,467

As discussed in Section 2.4.1 of the 2011v6.3 platform TSD, the EPA estimates for C3 CMV, emissions data were developed for year 2002 and projected to year 2011 for the 2011 base case, and used where states did not submit data to Version 2 of the 2011 NEI. Pollutant and geographic-specific projection factors to year 2011 were applied, along with projection factors to years 2023 that reflect assumed growth and final ECA-IMO controls. These emissions estimates reflect the EPA's coordinated strategy for large marine vessels. More information on the EPA's coordinated strategy for large marine vessels can be found in our Category 3 Marine Diesel Engines and Fuels regulation published in April 2010. That rule, as well as information about the North American and U.S. Caribbean Sea ECAs, designated by amendment to MARPOL Annex VI, can be found at: https://www.epa.gov/regulations-emissions-vehicles-and-engines/international-standards-reduce-emissions-marine-diesel.

Projection factors for creating the year 2023 cmv inventory from the 2011 base case are provided in Table 4-17. For more information on the mapping of the states to each EEZ, see Section 2.4.1 of the 2011v6.3 platform TSD. For example, Washington state emissions are grown the same as all North Pacific offshore emissions.

Table 4-17. Growth factors to project the 2011 ECA-IMO inventory to 2023

Region	**EEZ (offshore) FIPS**	**CO**	**NO_X**	**PM_{10}**	**PM_{25}**	**SO_2**	**VOC**
North Pacific (NP)	85001	1.49	0.85	0.2	0.2	0.06	1.49
South Pacific (SP)	85002	1.86	0.95	0.26	0.26	0.07	1.86
East Coast (EC)	85004	1.71	0.89	0.23	0.23	0.06	1.71
Gulf Coast (GC)	85003	1.42	0.75	0.19	0.19	0.05	1.42
Great Lakes (GL)	n/a	1.23	0.95	0.16	0.16	0.04	1.23
Outside ECA	98001	1.72	1.39	0.63	0.63	0.58	1.72

Packet for othpt:

"PROJECTION_2011_2023_C3_CMV_ECA_IMO_2011v6_3_02sep2016_v0.txt"

Note that the MARAMA packet provided in BETA_Projections_C3Marine_2023_20feb2016_emf_csv_02sep2016_v0.txt was not used because the offshore emissions were not in a MARAMA state. As discussed in Section 2.4.2 of the 2011v6.3 platform TSD, emissions outside the 3 to 10-mile coastal boundary, but within the approximately 200 nm EEZ boundaries, were projected to year 2023 using the same regional adjustment factors as the U.S. emissions; however, the FIPS codes were assigned as "EEZ" FIPS and these emissions are processed in the "othpt" sector. Note that state boundaries in the Great Lakes are an exception, extending through the middle of each lake such that all emissions in the Great Lakes are assigned to a U.S. county or Ontario. The classification of emissions to U.S.

and Canadian FIPS codes is needed to avoid double-counting of Canadian-provided C3 CMV emissions in the Great Lakes.

The cumulative impact of these ECA-IMO projections and controls to the U.S. + near-offshore (cmv sector) and far-offshore emissions (othpt sector) in 2023 is provided in Table 4-18.

Table 4-18. Difference in Category 3 cmv sector and othpt C3 CMV emissions between 2011 and 2023

Region	Pollutant	2011 emissions	2023 emissions	Difference 2023 - 2011
Offshore to EEZ*	CO	133,574	173,938	40,364
Offshore to EEZ*	NOX	798,258	728,724	-69,534
Offshore to EEZ*	PM10	28,451	6,854	-21,597
Offshore to EEZ*	PM2_5	26,113	6,293	-19,820
Offshore to EEZ*	SO2	222,113	16,509	-205,604
Offshore to EEZ*	VOC***	81,593	98,753	17,160
Non-US SECA C3	CO	187,439	321,978	134,539
Non-US SECA C3	NOX	2,209,800	3,078,374	868,574
Non-US SECA C3	PM10	187,587	118,375	-69,212
Non-US SECA C3	PM2_5	172,580	108,413	-64,167
Non-US SECA C3	SO2	1,391,702	803,736	-587,966
Non-US SECA C3	VOC***	79,575	136,692	57,117

* - Offshore to EEZ includes both c3marine, and the offshore oil rigs/etc from the US point inventory
*** - INCLUDES pre-speciated inventory VOC in Canada, so post-SMOKE VOC_INV < VOC

4.2.3.4 Upstream distribution, pipelines and refineries (nonpt, ptnonipm, pt_oilgas)

Packet:

ptnonpim and nonpt sectors only:
"PROJECTION_2011_2025_OTAQ_upstream_GasDist_pipelines_refineries_2011v6_2_05feb2015_05feb2015_v0.txt"
pt_oilgas sector only: "PROJECTION_2011v6_2025_pipelines_refineries
"BETA_Projections_OTAQ_Upstream_GasDist_2023_20feb2016_emf_csv_02sep2016_v0.txt" (MARAMA)

To account for projected increases in renewable fuel volumes due to the Renewable Fuel Standards (RFS2)/EISA (EPA, 2010a) and decreased gasoline volumes due to RFS2 and light-duty greenhouse gas standards as quantified in AEO 2014 (http://www.eia.gov/forecasts/archive/aeo14/), the EPA developed county-level inventory adjustments for gasoline and gasoline/ethanol blend transport and distribution. Here, for non-MARAMA states, year 2025 factors are used for year 2023. MARAMA provided year 2023-specific factors. These adjustments account for losses during truck, rail and waterways loading/unloading and intermodal transfers such as highway-to-rail, highways-to-waterways, and all other possible combinations of transfers. Adjustments for 2018 only account for impacts of RFS2, and the 2025 adjustments also account for additional impacts of greenhouse gas emission standards for motor vehicles (EPA, 2012b) on transported volumes. These emissions are entirely evaporative and, therefore, limited to VOC.

A 2018 inventory that included impacts of the EISA mandate was developed by applying adjustment factors to the 2011NEIv2 inventory. These adjustments were made using an updated version of the EPA's model for

upstream emission impacts, developed for the RFS2 rule[41]. The methodology used to make these adjustments is described in a 2014 memorandum included in the docket for the EPA Tier 3 rule (EPA, 2014)[42].

Ethanol emissions were estimated in SMOKE by applying the ethanol to VOC ratios from headspace profiles to VOC emissions for E10 and E15, and an evaporative emissions profile for E85. These ratios are 0.065 for E10, 0.272 for E15, and 0.61 for E85. The E10 and E15 profiles were obtained from an ORD analysis of fuel samples from EPAct exhaust test program[43] and were submitted for incorporation into the EPA's SPECIATE database. The E85 profile was obtained from data collected as part of the CRC E-80 test program (Environ, 2008) and was also submitted into the EPA's SPECIATE database. For more details on the change in speciation profiles between the base and future years, see Section 3.2 of the 2011v6.3 platform TSD.

Pipeline usage and refinery emissions were adjusted to account for impacts of the 2017-2025 light duty vehicle greenhouse gas emission standards, as well as renewable fuel volume projections. These adjustments were developed by the EPA's OTAQ and impact processes such as process heaters, catalytic cracking units, blowdown systems, wastewater treatment, condensers, cooling towers, flares and fugitive emissions. Calculation of the emission inventory impacts of decreased gasoline and diesel production, due to renewable fuel volume projections, on nationwide refinery emissions was done in the EPA's spreadsheet model for upstream emission impacts (EPA, 2009b). Emission inventory changes reflecting these impacts were used to develop adjustment factors that were applied to inventories for each petroleum refinery in the U.S. These impacts of decreased production were assumed to be spread evenly across all U.S. refineries. Toxic emissions were estimated in SMOKE by applying speciation to VOC emissions. It should be noted that the adjustment factors are estimated relative to that portion of refinery emissions associated with gasoline and diesel fuel production. Production of jet fuel, still gas and other products also produce emissions. If these emissions were included, the adjustment factors would not be as large.

The resulting adjustments for pipelines, refineries and the gasoline distribution processes (RBT, BPS and BTP) are provided in Table 4-19. Separate adjustments were applied to refinery to bulk terminal (RBT), bulk plant storage (BPS), and bulk terminal to gasoline dispensing pump (BTP) components. Emissions for the BTP component are greater than the RBT and BPS components. An additional adjustment was applied for 2025 at a national scale to account for impacts of gasoline volume reductions of the 2017-2025 light-duty greenhouse gas rule.

Notice that the "2011 Emissions" are not the same in Table 4-19. This is because these "2011" emissions are actually an intermediate set up projections applied after a first CoST strategy used to apply most other PROJECTION and CONTROL packets. We decided to first apply these other packets because we have multiple PROJECTION and CONTROL programs that impact the same emission sources. For this example, we applied year-specific industrial sector AEO-based growth (discussed in the next section) with our first CoST strategy, then applied these "EISA" adjustments on the results of this first CoST strategy. Similarly, we have RICE existing NESHAP, as well as NSPS, controls that need to be applied in separate strategies. Alternatively, we could have made "compound" CoST packets that combine these PROJECTION (and CONTROL) factors, but preferred to keep these packets separate for transparency. If we tried to process the multiple packets

[41] U.S. EPA. 2013. Spreadsheet "upstream_emissions_rev T3.xls.

[42] U. S. EPA. Development of Air Quality Reference Case Upstream and Portable Fuel Container Inventories for the Tier 3 Final Rule. Memorandum from Rich Cook, Margaret Zawacki and Zoltan Jung to the Docket. February 25, 2014. Docket EPA-HQ-OAR-2011-0135.

[43] U.S. EPA. 2011. Hydrocarbon Composition of Gasoline Vapor Emissions from Enclosed Fuel Tanks. Office of Research and Development and Office of Transportation and Air Quality. Report No. EPA-420-R-11-018. EPA Docket EPA-HQ-OAR-2011-0135.

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affecting the same sources in a single CoST strategy, CoST would either fail if the packet entries were the same key-field resolution (duplicate error), or, if packets were at a different key-field resolution, CoST would only apply the packet entry with higher priority according to Table 4-10.

Table 4-19. Petroleum pipelines & refineries and production storage and transport factors and reductions

Poll	Year	Factors			2011 Emissions	Reduction	Percent Reduction
		Pipelines & Refineries	RBT	BTP/BPS			
CO	2023	0.9445	n/a	n/a	53,501	2,969	5.55%
NOX	2023	0.9348	n/a	n/a	68,354	4,454	6.52%
PM10	2023	0.9668	n/a	n/a	24,484	813	3.32%
PM2.5	2023	0.9679	n/a	n/a	21,599	694	3.21%
SO2	2023	0.9517	n/a	n/a	78,944	3,815	4.83%
VOC	2023	0.9650	n/a	n/a	750,025	26,266	3.50%

4.2.3.5 Oil and gas and industrial source growth (nonpt, np_oilgas, ptnonipm, pt_oilgas)

Packets:

ptnonipm and nonpt sectors:
"PROJECTION_2011v6_2_2025_SCC_POINT_LADCO_09dec2014_09dec2014_v0.txt"
"PROJECTION_2011v6_2_2025_NAICS_SCC_SCA_orig_NEI_matched_CAPPED2_5_04dec2014_04dec2014_v0.txt"
"PROJECTION_2011v6_2_2025_SCC_POINT_SCA_orig_CAPPED_09dec2014_04feb2015_v1.txt"
"PROJECTION_2011v6_2_2025_SRAcapped_POINT_05dec2014_05dec2014_v0.txt"
'PROJECTION_TCEQ_ptnonipm_NAICS_comments_2011v6_2025_revised_16jul2015_v0.txt"
"PROJECTION_2011v6_2_2025_SCC_NONPOINT_LADCO_09dec2014_09dec2014_v0.txt"
"PROJECTION_2011v6_2_2025_SCC_NONPOINT_SCA_orig_CAPPED_09dec2014_09dec2014_v0.txt"
"PROJECTION_2011v6_2_2025_nonpoint_SCC_SRAcapped_05dec2014_05dec2014_v0.txt"
"PROJECTION_2011_2025_aircraft_ST_and_by_airport_22jan2015"
"PROJECTION_VA_ME_TCEQ_AL_comments_2011v6_2019_04dec2013_v0.txt"
"PROJECTION_2011v6_3__2017_Oklahoma_source_NODA_11jan2016_v1.txt"
"PROJECTION_2011v6_2_2025_TCEQ_v6_leftovers_NONPOINT_30jan2015_30jan2015_v0.txt"

np_oilgas sectors:
np_oilgas_offshore_coalbed_2011_2023en_projection_packet_03aug2017_v0.txt
np_oilgas_TCEQ_2014_2023_projection_packet_03aug2017_v0.txt
np_oilgas_2011_2023en_projection_packet_03aug2017_v0.txt
pt_oilgas sector:
OK_pt_oil_gas_projection_csv_06jan2016_v0.txt
PROJECTION_2011_2023_NAICS_SCC_SCA_orig_NEI_matched_CAPPED2_5_csv_04oct2016_v1.txt
PROJECTION_2011v6_2_2023_SCC_POINT_LADCO_csv_04oct2016_v0.txt
PROJECTION_2011v6_2_2023_SCC_POINT_SCA_orig_CAPPED_09dec2014_04oct2016_v0.txt
PROJECTION_2011v6_2_2023_SRAcapped_POINT_05dec2014_04oct2016_v0.txt
PROJECTION_TCEQ_ptnonipm_NAICS_comments_2011v6_2023_04dec2013_04oct2016_v0.txt
pt_oilgas_2011_2023en_projection_packet_03aug2017_v0.txt
PROJECTION_2011v6_2025_pipelines_refineries_26mar2014_v0.txt

MARAMA states: "BETA_Projections_NP_OILGAS_2023_22apr2016_emf.csv" (MARAMA: PA only)
"BETA_Projections_PT_OILGAS_2023_24aug2016_emf.csv" (MARAMA: PA only)
"BETA_Projections_PT_NonERTAC_2023_24aug2016_emf.csv" (MARAMA)
"BETA_Projections_PT_Small_EGU_2023_25jul2016_emf.csv" (MARAMA)
"BETA_Projections_NonPoint_2023_2016_08_24_emf.csv" (MARAMA)
"BETA_Projections_NONPT_REFUELING_2023_25jul2016_emf.csv" (MARAMA)

"BETA_Projections_Aircraft_Engine_GSE_APU_2023_10aug2016_emf.csv" (MARAMA)

The EPA provided a NODA (search for the docket 'EPA-HQ-OAR-2013-0809' on *regulations.gov*) for the 2011v6.0 emissions modeling platform and projected 2018 inventory in January, 2014. A significant number of the comments were about the EPA's "no growth" assumption for industrial stationary sources and about the current projection approach for oil and gas sources that was applied similarly to five broad geographic (NEMS) regions and limited to only oil and gas drilling activities.

With limited exceptions, the EPA used a no-growth assumption for all industrial non-EGU emissions since the 2005 NEI-based emissions modeling platform (EPA, 2006). However, comments provided to the EPA for this platform (via the NODA) and for previous modeling platforms suggested that this approach was insufficient. In addition, the NO_x Budget program, which had a direct impact on post-2002 emissions reductions, is in full compliance in the 2011 NEI. This means that additional large-scale industrial reductions should not be expected beyond 2011 in the absence of on-the-books state and federal rules.

In response to the comments about the EPA's no-growth and previous approaches, the EPA developed industrial sector activity-based growth factors. In response to the NODA, many states have additionally provided detailed activity-based projection factors for industrial sources, including oil and gas sources. To develop the methods described here, we have blended the state-provided growth factors with the EPA-developed industrial sector growth factors. This approach has attempted to balance using the specific information that is available with the EPA's interest in consistency for a given sector and technical credibility. Table 4-14 lists the new resulting data sources for industrial sector non-EGU growth factors that the EPA applied to estimate year 2023 emissions for this emissions modeling platform. Ultimately, there were three broad sources of projection information for industrial sources, including oil and gas; these sources are referenced as the following for simplicity:

1) EPA:
    a. **(NEW)** Reflects EPA-generated factors based on EIA state historical production data and AEO 2017 reference case production data (label dated "03aug2017").
    b. Reflects EPA-sponsored data provided by a contractor (SC&A, 2014a; SC&A, 2014b). Packet file names for these data include "SCA."
2) MARAMA:
    a. Reflects data submitted on behalf of Atlantic seaboard states from North Carolina through Maine, and extending west through Pennsylvania and West Virginia. Packet file names for these data include "SRA" (SRA, 2014).
    b. Reflects data submitted on behalf of Atlantic seaboard states from North Carolina through Maine, and extending west through Pennsylvania and West Virginia. Packet file names that begin with "BETA" (MARAMA, 2016).
3) LADCO: Reflects data submitted on behalf of Lake Michigan Air Directors Consortium (LADCO) states (MN, WI, MI, IL, IN, OH). Projection data from this data source are reflected in packet names containing "LADCO" (Alpine Geophysics, 2014).

Table 4-20. Sources of new industrial source growth factor data for year 2023 in the 2011v6.3 platform

Abbrev.	Source	Geographic Resolution	Inventory Resolution	Use/Caveat
MARAMA "BETA" packets	MARAMA/states using 2015 AEO data and other data sources	State or county for nonpoint and facility and below for most point sources	Facility and sub-facility for point, SCC-level for nonpoint	Provided by MARAMA (2016) for year-2023 specific projection purposes.
EPA New projection packets for 2023en case: "np_oilgas_offshore_coalbed_2011_2023en_projection_packet_03aug2017_v0.txt" "np_oilgas_TCEQ_2014_2023_projection_packet_03aug2017_v0.txt" "np_oilgas_2011_2023en_projection_packet_03aug2017_v0.txt" "pt_oilgas_2011_2023en_projection_packet_03aug2017_v0.txt"	Non-MARAMA states using EIA historical production state data and 2017 AEO Crude Oil Production and Natural Gas Production data	EIA Supply Region	State or county/ SCC	Impacts both point and nonpoint oil and gas sectors as well as some non-EGU point sources not in the pt_oilgas sector.

Table 4-20 above lists only the new projection packets used to estimate year 2023 emissions for this modeling effort. MARAMA provided year-2023 specific factors for all sectors mentioned in this section. The EPA generated factors using AEO2017 data were also year-2023 specific emissions. The previous TSDs for 2011v6.2 and 2011v6.3 describe the other packets mentioned earlier in this section. Specifically, year 2025 packets mentioned in this section are described in the 2011v6.2 TSD (EPA, 2015b).

Natural Gas Consumption and Crude Oil Production

In the 2023el case, the AEO 2016 reference case data (http://www.eia.gov/outlooks/aeo/tables_ref.cfm) was used to project production-related oil and gas sources. The AEO2016 tables used include the National Oil and Gas Supply Table #14, Lower 48 Crude Oil Production Table #60, and Lower 48 Natural Gas Production Table #61. These AEO2016 tables were used to project emissions related to oil and gas production for the six EIA Supply Regions (Figure 4-1) plus offshore regions. These projection factors were applied to appropriate production related SCCs in the NEI2011v2 inventory. In cases where a SCC description listed both oil and gas production processes may be involved, an average projection factor was used for that EIA Supply Region. For more details on the 2023el case approach, see the *Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the year 2023* technical support document (EPA, 2016b).

The method used in the 2023el case was released in a Notice of Data Availability (NODA), (82 FR 1733, Docket No. EPA-HQ-OAR-2016-0751). Comments on the methodology were solicited with the NODA. Some states and other stakeholders recommended future methodology updates for oil and gas projections. In particular, some commenters expressed strong interest in enhancing the methodology to better account for how states in a given multi-state region can have notably different trends in oil and gas production. In response to these comments, EPA updated the projection method in the 2023en case for production-related oil and gas emission sources to better account for differences in both historical and projected state oil and gas production trends.

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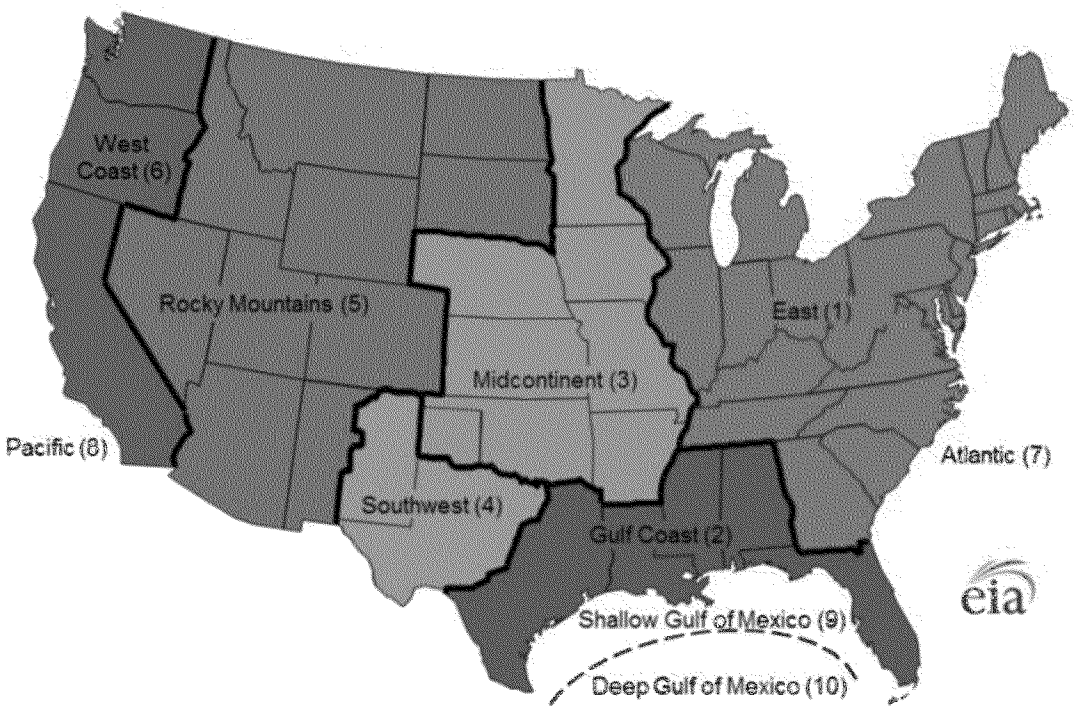
In the 2023en case, updated state-specific 2011-2023 projection factors were generated and applied. The projection factors used in the 2023en case are the products of multiplying historic (2011-2015) state-level factors by regional projection factors that represent 2015 to 2023.

- The 2011-2015 factors are based on historic state oil and gas production data published by EIA.
  - Crude oil production data
    - http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
  - Dry natural gas estimated production data
    - http://www.eia.gov/dnav/ng/ng_sum_lsum_a_epg0_r20_bcf_a.htm
- The 2015-2023 factors are based on projected oil and gas production in EIA's 2017 Annual Energy Outlook (AEO) Reference Case without the Clean Power Plan for the six EIA Supply Regions (Figure 4-1)

Figure 4-1. Oil and Gas NEMS Regions



Source: U.S. Energy Information Administration

To better differentiate state trends within each region, the following three assumptions were implemented which cause the projection factors to vary based on historic oil and gas production:

1. States without EIA oil and gas production data for 2011-2015 have their factor set to 1.0 for 2011-2015; a factor of 1.0 indicates that there is no growth from 2011-2015.
2. States without EIA oil and gas production data for 2011-2015 have 2015-2023 projection factors set to 1.0, unless the region containing the state has a 2015-2023 factor less than 1.0, in which case the lower regional factor will be applied.
3. If a state has a 2011-2015 projection factor less than 1.0 and its associated 2015-2023 regional factor is greater than 1.0, then the 2015-2023 factor is set to 1.0.

There were some states for which the approach had to be somewhat modified for various reasons. For example, in New Mexico which has counties falling into two different EIA Supply Regions in the 2017 AEO data, the 2011-2015 factors are state-specific and the 2015-2023 factors are region-specific. For Texas, which has counties falling into three different EIA Supply Regions in the 2017 AEO data, a 2014 emissions inventory provided in response to the NODA was paired with 2014-2023 projection factors that are region-specific. For Pennsylvania, the 2023el projection factors for the np_oilgas sector were used in the 2023en case. The net impacts of these projection factors for each of the modeling sectors is provided in Table 4-21. Specific projection factors for each state are available on the Projection Factors tab of the spreadsheet *2011_2023en_oil_gas_projections_082517.xlsx* available with the reports for the 2011v6.3 platform area of the FTP site: ftp://ftp.epa.gov/EmisInventory/2011v6/v3platform/reports/2011en_and_2023en/.

Table 4-21. Industrial source projections net impacts for 2023en

Pollutant	Sector	2011 Emissions Subject to projection	Intermediate Projected Emissions	Difference (Future - 2011)	% Difference (Future - 2011)
CO	nonpt	733,239	790,635	57,396	8%
CO	np_oilgas	669,611	861,154	191,544	29%
CO	pt_oilgas	235,236	290,468	55,232	23%
CO	ptnonipm	1,028,175	1,152,841	124,666	12%
CO	**Total**	**2,666,261**	**3,095,098**	**428,837**	**16%**
NH_3	nonpt	18,381	18,830	449	2%
NH_3	pt_oilgas	266	237	-29	-11%
NH_3	ptnonipm	12,645	13,473	828	7%
NH_3	**Total**	**31,291**	**32,540**	**1,248**	**4%**
NO_X	nonpt	499,419	517,606	18,187	4%
NO_X	np_oilgas	707,212	942,919	235,707	33%
NO_X	pt_oilgas	541,483	592,903	51,419	9%
NO_X	ptnonipm	713,372	799,033	85,662	12%
NO_X	**Total**	**2,461,486**	**2,852,461**	**390,975**	**16%**
PM_{10}	nonpt	280,933	315,788	34,856	12%
PM_{10}	np_oilgas	18,082	24,783	6,702	37%
PM_{10}	pt_oilgas	15,101	16,500	1,399	9%
PM_{10}	ptnonipm	140,965	159,778	18,812	13%
PM_{10}	**Total**	**455,081**	**516,849**	**61,768**	**14%**
$PM_{2.5}$	nonpt	224,860	254,129	29,268	13%
$PM_{2.5}$	np_oilgas	16,618	21,789	5,171	31%
$PM_{2.5}$	pt_oilgas	14,790	16,159	1,369	9%
$PM_{2.5}$	ptnonipm	114,104	130,535	16,431	14%
$PM_{2.5}$	**Total**	**370,372**	**422,612**	**52,239**	**14%**
SO_2	nonpt	253,885	237,039	-16,846	-7%
SO_2	np_oilgas	29,058	48,014	18,956	65%

Pollutant	Sector	2011 Emissions Subject to projection	Intermediate Projected Emissions	Difference (Future - 2011)	% Difference (Future - 2011)
SO_2	pt_oilgas	59,322	59,264	-58	0%
SO_2	ptnonipm	481,022	482,098	1,076	0%
SO_2	**Total**	**823,287**	**826,415**	**3,128**	**0%**
VOC	nonpt	1,133,960	1,189,481	55,520	5%
VOC	np_oilgas	2,563,018	3,849,332	1,286,314	50%
VOC	pt_oilgas	146,969	175,377	28,408	19%
VOC	ptnonipm	177,442	203,905	26,463	15%
VOC	**Total**	**4,021,389**	**5,418,095**	**1,396,706**	**35%**

4.2.3.6 Aircraft (ptnonipm)

Packet:

"PROJECTION_2011_2025_aircraft_ST_and_by_airport_22jan2015_v0.txt"
"BETA_Projections_Aircraft_Engine_GSE_APU_2023_10aug2016_emf.csv" (MARAMA)

Aircraft emissions are contained in the ptnonipm inventory. These 2011 point-source emissions are projected to future years by applying activity growth using data on ITN operations at airports. The ITN operations are defined as aircraft take-offs whereby the aircraft leaves the airport vicinity and lands at another airport, or aircraft landings whereby the aircraft has arrived from outside the airport vicinity. The EPA used projected ITN information available from the Federal Aviation Administration's (FAA) Terminal Area Forecast (TAF) System: https://www.faa.gov/data_research/aviation/taf/ (publication date March, 2014). This information is available for approximately 3,300 individual airports, for all years up to 2040. The methods that the FAA used for developing the ITN data in the TAF are documented in: http://www.faa.gov/about/office_org/headquarters_offices/apl/aviation_forecasts/taf_reports/media/TAF_Summary_Report_FY2013-2040.pdf.

None of our aircraft emission projections account for any control programs. The EPA considered the NOx standard adopted by the International Civil Aviation Organization's (ICAO) Committee on Aviation Environmental Protection (CAEP) in February 2004, which is expected to reduce NOx by approximately 3 percent by 2020. However, this rule has not yet been adopted as an EPA (or U.S.) rule and, therefore, its effects were not included in the future-year emissions projections.

The EPA developed two sets of projection factors for aircraft. The first set was a simple state-level aggregation, used primarily for airports with very little activity, by ITN operation type (commercial, general aviation, military and air taxi) to be used as a default method for projecting from 2011 to future years. The second set of projection factors was by airport, where the EPA projects emissions for each individual airport with significant ITN activity.

Where NEI facility identifiers were not matched to FAA airport identifiers, we simply summed the ITN operations to state totals by year and aircraft operation and computed projection factors as future-year ITN to year-2011 ITN. The EPA assigned factors to inventory SCCs based on the operation type shown in Table 4-22.

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Table 4-22. NEI SCC to FAA TAF ITN aircraft categories used for aircraft projections

SCC	Description	FAA ITN Type
2265008005	Commercial Aircraft: 4-stroke Airport Ground Support Equipment	Commercial
2267008005	Commercial Aircraft: LPG Airport Ground Support Equipment	Commercial
2268008005	Commercial Aircraft: CNG Airport Ground Support Equipment	Commercial
2270008005	Commercial Aircraft: Diesel Airport Ground Support Equipment	Commercial
2275000000	All Aircraft Types and Operations	Commercial
2275001000	Military Aircraft, Total	Military
2275020000	Commercial Aviation, Total	Commercial
2275050011	General Aviation, Piston	General
2275050012	General Aviation, Turbine	General
2275060011	Air Taxi, Total: Air Taxi, Piston	Air Taxi
2275060012	Air Taxi, Total: Air Taxi, Turbine	Air Taxi
2275070000	Commercial Aircraft: Aircraft Auxiliary Power Units, Total	Commercial
27501015	Internal Combustion Engines; Fixed Wing Aircraft L & TO Exhaust; Military; Jet Engine: JP-5	Military
27502011	Internal Combustion Engines; Fixed Wing Aircraft L & TO Exhaust; Commercial; Jet Engine: Jet A	Commercial
27505001	Internal Combustion Engines; Fixed Wing Aircraft L & TO Exhaust; Civil; Piston Engine: Aviation Gas	General
27505011	Internal Combustion Engines; Fixed Wing Aircraft L & TO Exhaust; Civil; Jet Engine: Jet A	General

Most NEI airports matched FAA TAF identifiers and, therefore, use airport-specific projection factors. We applied a cap on projection factors of 2.0 (100 percent increase) for state-level defaults and 5.0 for airport-specific entries. None of the largest airports/larger-emitters had projection factors close to these caps. A national summary of aircraft emissions between 2011 and future year 2023 are provided in Table 4-23.

Table 4-23. National aircraft emission projection summary for 2023en

	Emissions		Difference	% Difference
	2011	2025	2025-2011	2025
CO	489,854	559,783	69,930	14.28%
NO_X	120,968	157,610	36,642	30.29%
PM_{10}	9,164	10,039	874	9.54%
$PM_{2.5}$	7,891	8,709	818	10.37%
SO_2	14,207	18,139	3,932	27.67%
VOC	32,023	38,077	6,054	18.90%

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4.2.3.7 Cement manufacturing (ptnonipm)

Packet:

"PROJECTION_2011_2025_ISIS_cement_by_CENSUS_DIVISION.txt"

As indicated in Table 4-1, the Industrial Sectors Modeling Platform (ISMP) (EPA, 2010b) was used to project the cement industry component of the ptnonipm emissions modeling sector to 2025; we used year 2025 emissions for year 2023. This approach provided reductions of criteria and select hazardous air pollutants. The ISMP cement emissions were developed in support for the Portland Cement NESHAPs and the NSPS for the Portland cement manufacturing industry.

The ISMP model produced a Portland Cement NESHAP policy case of multi-pollutant emissions for individual cement kilns (emission inventory units) that were relevant for years 2015 through 2030. These ISMP-based emissions are reflected using a CoST packet for all existing kilns that are not impacted by more local information from states (or consent decrees). ISMP also generates new cement kilns that are permitted (point inventory) and not-permitted, but generated based on ISMP assumptions on demand and infrastructure (nonpt inventory). These new cement kilns are discussed in Section 4.2.5.4.

The PROJECTION packets contain U.S. census division level based projection factors for each NEI unit (kiln) based on ISMP updated policy case emissions at existing cement kilns. The units that closed before 2025 are included in the 2025 base case but are included in other CoST packets that reflect state comments and consent decrees (discussed in Section 4.2.4.11).

The ISMP model, version August 2013, was used for these projections. Recent data updates include updated matching of kilns to better capture recent retirements, capacity additions and projections of capacity additions from Portland Cement Association (PCA) Plant Information Summary of December 31, 2010, and feedback from Portland Cement NESHAP reconsideration comments. Updated cement consumption projections are based on a post-recession (July 2012) PCA long-term cement consumption outlook. Updated emissions controls in 2015 from the NESHAP are also reflected. Overall, as seen in Figure 4-2, domestic production of cement grows significantly between 2011 and 2015, then more slowly through 2018. Meanwhile, emissions from NESHAP-regulated pollutants such as PM and SO_2 drop significantly based on regulated emissions rates. Emissions for NOx increase, though not as much as production because the ISMP model continues the recent trend in the cement sector of the replacement of lower capacity, inefficient wet and long dry kilns with bigger and more efficient preheater and precalciner kilns.

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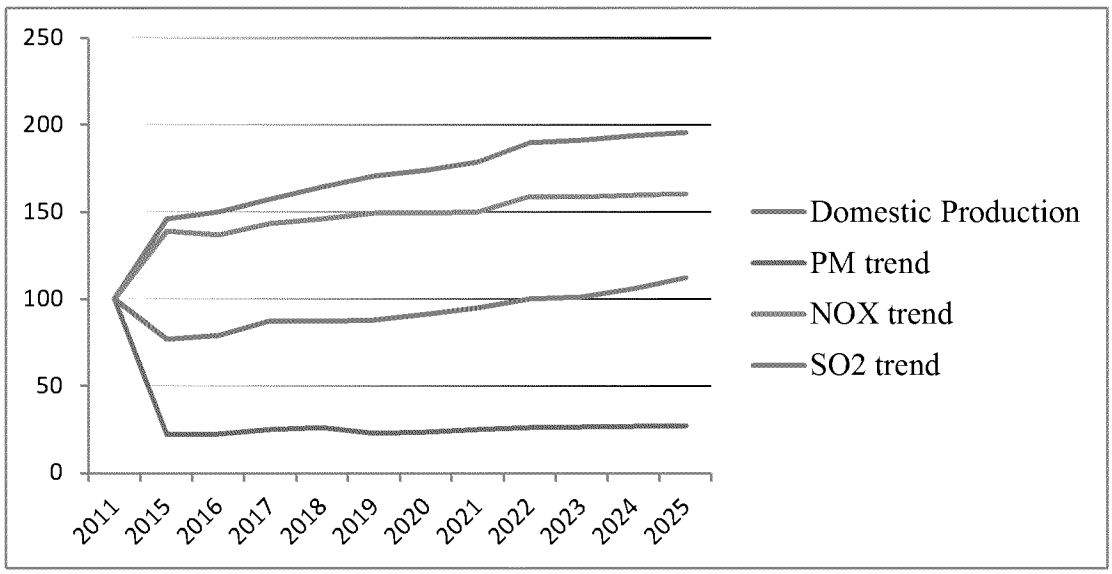
Figure 4-2. Cement sector trends in domestic production versus normalized emissions



Multiple regulatory requirements such as the NESHAP and NSPS currently apply to the cement industry to reduce CAP and HAP emissions. Additionally, state and local regulatory requirements might apply to individual cement facilities depending on their locations relative to ozone and $PM_{2.5}$ nonattainment areas. The ISMP model provides the emission reduction strategy that balances: 1) optimal (least cost) industry operation; 2) cost-effective controls to meet the demand for cement; and 3) emission reduction requirements over the time period of interest.

The first step in using ISMP 2025 projected emissions is matching the kilns in future years to those in the 2011 NEI. While ISMP provides by-kiln emissions for each future year, the EPA cement kilns experts preferred that the agency project existing cement kilns based on a more-smooth geographic approach to reduce the "on/off" switching that ISMP assigns to each kiln based on production and capacity demands. It would be inefficient and unrealistic to project existing cement kilns to operate as essentially 0 percent or 100 percent capacity based strictly on ISMP output. Therefore, the EPA developed a U.S. Census Division approach where ISMP emissions in 2011 and future years, that matched the 2011 NEI (e.g., not new ISMP kilns), were aggregated by pollutant for each year within each of the nine census divisions in the contiguous U.S. (http://www.eia.gov/consumption/commercial/images/cendivco.gif). These aggregate emissions were used to create 2025/2011 emissions ratios for each pollutant and geographic area. The projection ratios, provided in Table 4-24, were then applied to all 2011 NEI cement kilns, except for kilns where specific local information (e.g., consent decrees/settlements/local information) was available.

Table 4-24. U.S. Census Division ISMP-based projection factors for existing kilns

Region	Division	NOx	PM	SO_2	VOC
		2025	2025	2025	2025
Midwest	East North Central	2.053	0.144	3.034	0.67
Midwest	West North Central	1.279	0.673	1.262	0.492
Northeast	Middle Atlantic	1.221	0.119	0.867	0.569
Northeast	New England	2.56	0.004	3.563	0.713

South	East South Central	0.999	0.109	0.402	0.323
South	South Atlantic	1.077	0.339	0.936	0.42
South	West South Central	1.526	0.174	0.664	0.252
West	Mountain	1.321	1.032	1.366	0.345
West	Pacific	1.465	0.006	0.251	0.29

Table 4-25 shows the magnitude of the ISMP census division based projected cement industry emissions at existing NEI facilities from 2011 to future year 2025; we use 2025 projected emissions for year 2023. Additional new kiln emissions generated by ISMP are discussed in Section 4.2.5.4. There are some local exceptions where the EPA did not use ISMP-based projections for cement kilns where local information from consent decrees/settlements and state comments were used instead. Cement kilns projected using these non-ISMP information are not reflected here in Table 4-25.

Table 4-25. ISMP-based cement industry projected emissions for 2023en

	Emissions		**Tons Difference**	**% Difference**
	2011	**2025**	**2025**	**2025**
NO_X	47,270	67,856	20,586	43.6%
PM_{10}	2,743	967	-1,776	-64.8%
$PM_{2.5}$	1,523	598	-925	-60.7%
SO_2	11,520	21,534	10,014	86.9%
VOC	2,329	940	-1,390	-59.7%

4.2.3.8 Corn ethanol plants (ptnonipm)

Packet:

"PROJECTION_2011_2025_Corn_Ethanol_Plants_AEO2014_Table17_2011v6.2_19feb2015_v0.txt"

We used the AEO 2014 renewable forecast projections of "From Corn and Other Starch" to compute national year 2025 growth in ethanol plant production. Per OTAQ direction, we exempted two facilities ('Highwater Ethanol LLC' in Redwood county MN and 'Life Line Foods LLC-St. Joseph' in Buchanan county MO) from these projections; future year emissions were equal to their 2011 NEI v2 values for these two facilities.

The 2011 corn ethanol plant emissions were projected to account for the change in domestic corn ethanol production between 2011 and future years, from approximately 13.9 Bgal (billion gallons) in 2011 to 13.2 Bgal by 2025 based on AEO 2014 projections. The projection was applied to all pollutants and all facilities equally. Table 4-26 provides the summaries of estimated emissions for the corn ethanol plants in 2011 and future year 2025.

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Table 4-26. 2011 and 2025 corn ethanol plant emissions [tons]

	Emissions		Difference	% Change
	2011	2025	2025	2025
CO	877	831	-46	-5.19%
NO_x	1,328	1,259	-69	-5.19%
PM_{10}	1,259	1,194	-65	-5.19%
$PM_{2.5}$	302.243	286.545	-16	-5.19%
SO_2	9.52755	9.03272	0	-5.19%
VOC	3,084	2,924	-160	-5.19%

4.2.3.9 Residential wood combustion (rwc)

Packet:

"PROJECTION_2011_2023_RWC_2011v6.3.csv"
"BETA_Projections_RWC_2023_18apr2016_emf.csv" (MARAMA)

The EPA applied the recently-promulgated national NSPS for wood stoves to the RWC projections methodology for this platform. To learn more about the strengthened NSPS for residential wood heaters, see http://www2.epa.gov/residential-wood-heaters/regulatory-actions-residential-wood-heaters. The EPA projected RWC emissions to year 2017 and 2025 based on expected increases and decreases in various residential wood burning appliances. The EPA linearly interpolated these factors to year 2023 for this modeling platform. As newer, cleaner woodstoves replace ***some*** older, higher-polluting wood stoves, there will be an overall reduction of the emissions from older "dirty" stoves but an overall increase in total RWC due to population and sales trends in all other types of wood burning devices such as indoor furnaces and outdoor hydronic heaters (OHH). It is important to note that our RWC projection methodology does not explicitly account for state or local residential wood control programs. There are a number more-stringent state and local rules in place in 2011, specifically in California, Oregon and Washington. However, at this time, the EPA does not have enough detailed information to calculate state specific or local area growth rates. Therefore, with the exception of California, Oregon and Washington, the EPA is using national level growth rates for each RWC SCC category. After discussions with California air districts, regional office contacts and EPA experts, the EPA decided to hold RWC emissions flat (unchanged) for all SCCs in California, Oregon and Washington.

Assumed Appliance Growth and Replacement Rates

The development of projected growth in RWC emissions to year 2017 and 2025 starts with the projected growth in RWC appliances derived from year 2012 appliance shipments reported in the Regulatory Impact Analysis (RIA) for Proposed Residential Wood Heaters NSPS Revision Final Report (EPA, 2013b), also available at: http://www2.epa.gov/sites/production/files/2013-12/documents/ria-20140103.pdf. The 2012 shipments are based on 2008 shipment data and revenue forecasts from a Frost & Sullivan Market Report (Frost & Sullivan, 2010). Next, to be consistent with the RIA (EPA, 2013b), growth rates for new appliances for certified wood stoves, pellet stoves, indoor furnaces and OHH were based on forecasted revenue (real GDP) growth rate of 2.0 percent per year from 2013 through 2025 as predicted by the U.S. Bureau of Economic Analysis (BEA, 2012). While this approach is not perfectly correlated, in the absence of specific shipment projections, the RIA assumes the overall trend in the projection is reasonable. The growth rates for appliances not listed in the RIA (fireplaces, outdoor wood burning devices (not elsewhere classified) and residential fire logs) are estimated

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based on the average growth in the number of houses between 2002 and 2012, about 1 percent (U.S. Census, 2012).

In addition to new appliance sales and forecasts extrapolating beyond 2012, assumptions on the replacement of older, existing appliances are needed. Based on long lifetimes, no replacement of fireplaces, outdoor wood burning devices (not elsewhere classified) or residential fire logs is assumed. It is assumed that 95 percent of new woodstoves will replace older non-EPA certified freestanding stoves (pre-1988 NSPS) and 5 percent will replace existing EPA-certified catalytic and non-catalytic stoves that currently meet the 1988 NSPS (Houck, 2011).

The EPA RWC NSPS experts assume that 10 percent of new pellet stoves and OHH replace older units and that because of their short lifespan, that 10 percent of indoor furnaces are replaced each year; these are the same assumptions used since the 2007 emissions modeling platform (EPA, 2012d). The resulting growth factors for these appliance types varies by appliance type and also by pollutant because the emission rates, from EPA RWC tool (EPA, 2013rwc), vary by appliance type and pollutant. For EPA certified units, the projection factors for PM are lower than those for all other pollutants. The projection factors also vary because the total number of existing units in 2011 varies greatly between appliance types.

NSPS Overview

The residential wood heaters NSPS final rule was promulgated on February 3, 2015. This rule does not affect existing woodstoves or other wood burning devices; however, it does provide more stringent emissions standards for new woodstoves, outdoor hydronic heaters and indoor wood-burning forced air furnaces. New "Phase 1" less-polluting heater standards began in 2015, with even more-stringent Phase 2 standards beginning in 2020. The associated reduced emission rates for each appliance type (SCC) are applied to all new units sold, some of which are assumed to replace retired units, since year 2015.

Currently the 1988 NSPS limits primary $PM_{2.5}$ emissions from adjustable burn rate stoves, including fireplace inserts and freestanding woodstoves, to 7.5 grams/hour (g/hr) for non-catalytic stoves and 4.1 g/hr for catalytic stoves. The final NSPS limits $PM_{2.5}$ emissions for room heaters, which include adjustable and single burn rate stoves and pellet stoves to 4.5 g/hr in 2015 and 1.3 g/hr in 2020. In addition, the final NSPS limits $PM_{2.5}$ emissions from hydronic heaters to 0.32 lb/MMBtu heat output in 2015, and 0.06 lb/MMBtu in 2020. The final NSPS limits $PM_{2.5}$ emissions from indoor furnaces to 0.93 lb/MMBtu in 2015 and 0.06/MMBtu in 2020.

Emission factors were estimated from the 2011v2 NEI based on tons of emissions per appliance for $PM_{2.5}$, VOC and CO. This calculation was based on estimated appliance (SCC) population and total emissions by SCC. EPA-certified wood stove emission factors are provided in the wood heaters NSPS RIA Tables 4-3, 4-7 and 4-11 for $PM_{2.5}$, VOC and CO, respectively. For all RWC appliances subject to the NSPS, baseline RIA emission factors, when lower than the computed emission factors (2011 NEI), are used for new appliances sold between 2012 and 2014. Starting in 2015, Phase 1 emission limits are 60 percent stronger (0.45 g/hr / 0.75 g/hr) than the RIA baseline emission factors. There are also different standards for catalytic versus non-catalytic EPA-certified stoves. Similar calculations are performed for Phase 2 emission limits that begin in 2020 and for different emission rates for different appliance types. Because the 2011NEI and RIA baseline (2012-2014) emission factors vary by pollutant, all RWC appliances subject to the NSPS have pollutant-specific "projection" factors. We realize that these "projection" factors are a composite of growth, retirements and potentially emission factors in 4 increments. More detailed documentation on the EPA RWC Projection Tool, including information on baseline, new appliances pre-NSPS, and Phase 1 and Phase 2 emission factors, is available upon request.

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Caveats and Results

California, Oregon and Washington have state-level RWC control programs, including local burn bans in place. Without an ability to incorporate significant local RWC control programs/burn bans for a future year inventory, the EPA left RWC emissions unchanged in the future for all three states. The RWC projections factors for states other than California, Oregon and Washington are provided in Table 4-27. VOC HAPs use the same projection factors as VOC; PM_{10} uses the same factor as $PM_{2.5}$; and all other pollutants use the CO projection factor. Note that appliance types not subject to the wood heaters NSPS (e.g., fire pits, fire logs) have pollutant-independent projection factors because there is no assumed change in future year emission factors.

Table 4-27. Non-West Coast RWC projection factors, including NSPS impacts

SCC	Description	Default if pollutant not defined	PM	VOC and VOC HAPs	CO and remaining CAPs
2104008100	Fireplace: general	1.127			
2104008210	Woodstove: fireplace inserts; non-EPA certified	0.791			
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	1.238	1.103		
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	1.281	1.128		
2104008310	Woodstove: freestanding, non-EPA certified	0.829	0.828	0.842	0.829
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	1.238	1.103		
2104008330	Woodstove: freestanding, EPA certified, catalytic	1.281	1.129		
2104008400	Woodstove: pellet-fired, general	1.852	1.898		
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	0.277	0.318	0.276	0.277
2104008610	Hydronic heater: outdoor	1.044	1.079		
2104008700	Outdoor wood burning device, NEC	1.127			
2104009000	Residential Firelog Total: All Combustor Types	1.127			

National emission summaries for the RWC sector in 2011 and 2023 are provided in Table 4-**28**. For direct PM, the NSPS emission factor reductions mostly offset the growth in appliances by year 2023.

Table 4-28**.** Cumulative national RWC emissions from growth, retirements, and NSPS impacts

Pollutant	Emissions		Difference	% Difference
	2011	2023	2023 - 2011	2023- 2011
CO	2,526,548	2,376,924	149,624	5.92%
NH_3	19,759	18,560	1,199	6.07%
NO_X	34,518	35,000	-483	-1.40%
PM_{10}	382,754	364,067	18,687	4.88%
$PM_{2.5}$	382,528	363,818	18,710	4.89%

Pollutant	Emissions		Difference	% Difference
	2011	2023	2023 - 2011	2023- 2011
SO_2	8,975	7,926	1,049	11.68%
VOC	444,269	417,315	26,954	6.07%

4.2.4 CoST CONTROL Packets (nonpt, np_oilgas, ptnonipm, pt_oilgas)

The final step in a CoST control strategy, after application of any/all CLOSURE packet(s) (point inventories only) and any/all PROJECTION packet(s) is the application of CoST CONTROL packets. While some controls are embedded in our PROJECTION packets (e.g., NSPS controls for RWC and loco-marine controls for rail and commercial marine vessels), we attempted to separate out the control (program) component in our modeling platform where feasible. In our platform, CoST control packets only impact the nonpt, np_oilgas, ptnonipm and pt_oilgas sectors.

There are several different sources of CONTROL data that are concatenated and quality-assured for duplicates and applicability to the inventories in the CoST strategies. We broke up the CONTROL (and PROJECTION) packets into a few "key" control program types to allow for quick summaries of these distinct control programs. The remainder of this section is broken out by CoST packet, with the exception of discussion of the various packets gathered from previous versions of the emissions modeling platform; these packets are a mix of different sources of data, only some of which have not been replaced by more recent information gathered for this platform.

For future-year NSPS controls (oil and gas, RICE, Natural Gas Turbines, and Process Heaters), we attempted to control only new sources/equipment using the following equation to account for growth and retirement of existing sources and the differences between the new and existing source emission rates.

$$Qn = Qo \{ [(1 + Pf) t - 1] Fn + (1 - Ri) t \ Fe + [1 - (1 - Ri) t] Fn] \} \qquad \textit{Equation 1}$$

where:

Qn = emissions in projection year
Qo = emissions in base year
Pf = growth rate expressed as ratio (e.g., 1.5=50 percent cumulative growth)
t = number of years between base and future years
Fn = emission factor ratio for new sources
Ri = retirement rate, expressed as whole number (e.g., 3.3 percent=0.033)
Fe = emission factor ratio for existing sources

The first term in Equation 1 represents new source growth and controls, the second term accounts for retirement and controls for existing sources, and the third term accounts for replacement source controls. For computing the CoST % reductions (Control Efficiency), the simplified Equation 2 was used for 2023 projections:

$$Control\_Efficiency_{2023}(\%) = 100 * (1- [(Pf_{2023}-1)*Fn + (1-Ri)^{12} + (1-(1-Ri)^{12})*Fn]/ Pf_{2023}) \qquad \text{Equation 2}$$

Here, the existing source emissions factor (Fe) is set to 1.0, 2023 (future year) minus 2011 (base year) is 12, and new source emission factor (Fn) is the ratio of the NSPS emission factor to the existing emission factor. Table 4-29 shows the values for Retirement rate and new source emission factors (Fn) for new sources with respect to each NSPS regulation and other conditions within; this table also provides the subsection where the CONTROL packets are discussed.

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Table 4-29. Assumed retirement rates and new source emission factor ratios for various NSPS rules

NSPS Rule	TSD Section	Retirement Rate years (%/year)	Pollutants Impacted	Applied where?	New Source Emission Factor (Fn)
Oil and Gas	4.2.4.1	No assumption	VOC	Storage Tanks: 70.3% reduction in growth-only (>1.0)	0.297
				Gas Well Completions: 95% control (regardless)	0.05
				Pneumatic controllers, not high-bleed >6scfm or low-bleed: 77% reduction in growth-only (>1.0)	0.23
				Pneumatic controllers, high-bleed >6scfm or low-bleed: 100% reduction in growth-only (>1.0)	0.00
				Compressor Seals: 79.9% reduction in growth-only (>1.0)	0.201
				Fugitive Emissions: 60% Valves, flanges, connections, pumps, open-ended lines, and other	0.40
				Pneumatic Pumps: 71.3% Oil and Gas	0.287
RICE	4.2.4.3	40, (2.5%)	NO_X	Lean burn: PA, all other states	0.25, 0.606
				Rich Burn: PA, all other states	0.1, 0.069
				Combined (average) LB/RB: PA, other states	0.175, 0.338
			CO	Lean burn: PA, all other states	1.0 (n/a), 0.889
				Rich Burn: PA, all other states	0.15, 0.25
				Combined (average) LB/RB: PA, other states	0.575, 0.569
			VOC	Lean burn: PA, all other states	0.125, n/a
				Rich Burn: PA, all other states	0.1, n/a
				Combined (average) LB/RB: PA, other states	0.1125, n/a
Gas Turbines	4.2.4.6	45 (2.2%)	NO_X	California and NO_X SIP Call states	0.595
				All other states	0.238
Process Heaters	4.2.4.7	30 (3.3%)	NO_X	Nationally to Process Heater SCCs	0.41

4.2.4.1 Oil and Gas NSPS (np_oilgas, pt_oilgas)

Packet:
"oilgas_2011_2023en_control_packet_NSPS_27jul2017_07aug2017_v0"
"CONTROL_2023_OILGAS_VOC_NSPS_csv_07aug2017_v2"
"BETA_Controls_OilGas_NSPS_2023_29apr2016.csv" (MARAMA)

For oil and gas NSPS controls, with the exception of gas well completions (a 95 percent control), the assumption of no equipment retirements through year 2023 dictates that NSPS controls are applied to the growth component only of any PROJECTION factors. For example, if a growth factor is 1.5 for storage tanks (indicating a 50 percent increase activity), then, using Table 4-29, the 70.3 percent VOC NSPS control to this new growth will result in a 23.4 percent control: 100 *(70.3 * (1.5 -1) / 1.5); this yields an "effective" growth rate (combined PROJECTION and CONTROL) of 1.1485, or a 70.3 percent reduction from 1.5 to 1.0. The impacts of all non-drilling completion VOC NSPS controls are therefore greater where growth in oil and gas production is assumed highest. Conversely, for oil and gas basins with assumed negative growth in activity/production, VOC NSPS controls will be limited to well completions only. Because these impacts are so geographically varying, we are providing the VOC NSPS reductions by each of the 6 broad NEMS regions, with Texas and New Mexico aggregated because these states include multiple NEMS regions (see Figure 4-1). These reductions are year-specific because projection factors for these sources are year-specific.

Table 4-30. NSPS VOC oil and gas reductions from projected pre-control 2023en grown values

Region	Pre-NSPS emissions	Post-NSPS emissions	NSPS Reductions	NSPS % reductions
Gulf Coast	1,066	53	1,013	95%
Midcontinent	72,774	58,883	13,891	19%
New Mexico/Texas*	1,250,016	914,867	335,149	27%
Northeast	291,465	123,494	167,970	58%
Rocky Mountains	753,719	388,716	365,002	48%
West Coast	358	30	328	92%
Overall	2,369,397	1,486,043	883,354	37%

4.2.4.2 RICE NESHAP (nonpt, np_oilgas, ptnonipm, pt_oilgas)

Packet:

"CONTROL_2011v6.2_RICE_NESHAP_v2_30jan2015_v0.txt"
"BETA_Controls_RICE_NESHAP_29apr2016" (MARAMA)

There are two rulemakings for National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE). These rules reduce HAPs from existing and new RICE sources. In order to meet the standards, existing sources with certain types of engines will need to install controls. In addition to reducing HAPs, these controls have co-benefits that also reduce CAPs, specifically, CO, NOx, VOC, PM, and SO_2. In 2014 and beyond, compliance dates have passed for both rules and are thus included in emissions projections. These RICE reductions also reflect the Reconsideration Amendments (proposed in January, 2012), which result in significantly less stringent NOx controls (fewer reductions) than the 2010 final rules.

The rules can be found at https://www.epa.gov/stationary-engines and are listed below:

- National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule (FR 9648) published 03/03/10.

- National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule (75 FR 51570) published 08/20/2010.

The difference among these two rules is that they focus on different types of engines, different facility types (major for HAPs, versus area for HAPs) and different engine sizes based on horsepower. In addition, they have different compliance dates, though both are after 2011 and fully implemented prior to 2017. The EPA projects CAPs from the 2011NEIv2 RICE sources, based on the requirements of the rule for existing sources only because the inventory includes only existing sources. The EPA estimates the NSPS (new source) impacts from RICE regulations in a separate CONTROL packet and CoST strategy; the RICE NSPS is discussed in the next section.

The "Regulatory Impact Analysis (RIA) for the Reconsideration of the Existing Stationary Compression Ignition (CI) Engines NESHAP: Final Report" (EPA, 2013ci) is available at: http://www.epa.gov/ttn/ecas/regdata/RIAs/RICE_NESHAPreconsideration_Compression_Ignition_Engines_RIA_final2013_EPA.pdf. The "Regulatory Impact Analysis (RIA) for Reconsideration of the Existing Stationary Spark Ignition (SI) RICE NESHAP: Final Report" (EPA, 2013si) is available at: http://www.epa.gov/ttn/ecas/regdata/RIAs/NESHAP_RICE_Spark_Ignition_RIA_finalreconsideration2013_EPA.pdf. Together, the EPA calls these the RICE NESHAP amendment RIA's for SI and CI engines. From these RICE NESHAP RIA documents, the EPA obtained cumulative RICE reductions for all SCCs represented by CI and SI engines. These aggregate reductions and percent reductions from baseline emissions (not the 2011NEIv2) are provided in Table 4-31. This table reflects the impacts of both the MARAMA and non-MARAMA packets.

Table 4-31. Summary RICE NESHAP SI and CI percent reductions prior to 2011NEIv2 analysis

	CO	**NO_X**	**PM**	**SO_2**	**VOC**
RIA Baseline: SI engines	637,756	932,377			127,170
RIA Reductions: SI engines	22,211	9,648			9,147
RIA Baseline: CI engines	81,145		19,369	11,053	79,965
RIA Reductions: CI engines	14,238		2,818	5,100	27,142
RIA Cumulative Reductions	36,449	9,638	2,818	5,100	36,289
SI % reduction	3.5%	1.0%	n/a	n/a	7.2%
CI % reduction	17.5%	n/a	14.5%	46.1%	33.9%

These RIA percent reductions were used as an ***upper-bound*** for reducing emissions from RICE SCCs in the 2011NEIv2 point and nonpoint modeling sectors (ptnonipm, nonpt, pt_oilgas and np_oilgas). To begin with, the RIA inventories are based on the 2005 NEI, so the EPA wanted to ensure that our 2011 reductions did not exceed those in the RICE RIA documents. For the 2011 platform, the EPA worked with EPA RICE NESHAP experts and developed a fairly simple approach to estimate RICE NESHAP reductions. Most SCCs in the inventory are not broken down by horsepower size range, mode of operation (e.g., emergency mode), nor major versus area source type. Therefore, the EPA summed NEI emissions nationally by SCC for RICE sources and also for sources that were at least partially IC engines (e.g., "Boiler and IC engines"). Then, the EPA applied the RIA percent reductions to the 2011NEIv2 for SCCs where national totals exceeded 100 tons; the EPA chose 100 tons as a threshold, assuming there would be little to no application of RICE NESHAP controls on smaller existing sources.

Next, the EPA aggregated these national reductions by engine type (CI vs. SI) and pollutant and compared these to the RIA reductions. As expected, for most pollutants and engine types, the cumulative reductions were significantly less than those in the RIA. The only exception was for SO_2 CI engines, where the EPA scaled the RIA percent reduction from 46.1 percent to 14.4 percent for four broad nonpoint SCCs that were not restricted to only RICE engines. These four SCCs were the "Boilers and IC Engines" or "All processes" that would presumably contain some fraction of non-RICE component. This had minimal impact as sulfur content in

distillate fuel for many IC engine types has decreased significantly since 2005. Reducing the SO_2 percent reduction for these four SCCs resulted in slightly less than 5,100 tons of SO_2 reductions overall from only RICE NESHAP controls. However, more specific CoST projection packets would later override these RICE NESHAP reductions for SO_2. Recall the CoST hierarchy discussed earlier; these RICE NESHAP reductions are national by pollutant and SCC and thus easily overridden by more-specific information such as state-level fuel sulfur rules (discussed in the next section).

Additional comments from the NODA were also implemented; specifically, CO controls were modified for a couple of distillate-fueled industrial/commercial boiler sources. Impacts of the RICE NESHAP controls on nonpt, ptnonipm, pt_oilgas and np_oilgas sector emissions are provided in Table 4-32. This table reflects the impacts of both the MARAMA and non-MARAMA packets.

Table 4-32. National by-sector reductions from RICE Reconsideration controls for 2023en (tons)

Pollutant	Year	Nonpoint Oil & Gas (np_oilgas)	Point Oil & Gas (pt_oilgas)	Nonpoint (nonpt)	Point (ptnonipm)	Total
CO	2023	11,051	5,452	3,505	6,357	26,365
NOX	2023	3,008	2,238	216	83	5,545
PM10	2023	0	8	1,038	306	1,352
PM2.5	2023	0	8	913	289	1,210
SO2	2023	0	11	2,951	307	3,269
VOC	2023	2,192	3,723	622	934	7,471

4.2.4.3 RICE NSPS (nonpt, np_oilgas, ptnonipm, pt_oilgas)

Packet:

"oilgas_2011_2023en_control_packet_RICE_NSPS_27jul2017_07aug2017_v0"
"CONTROL_2011v6_3_2023_RICE_NSPS_18oct2016_07aug2017_v1:

"BETA_Controls_RICE_NSPS_2023_30jul2016_csv_07aug2017_v1" (MARAMA)

Controls for existing RICE source emissions were discussed in the previous section. This section discusses control for new equipment sources, NSPS controls that impact CO, NOx and VOC. The EPA emission requirements for stationary engines differ according to whether the engine is new or existing, whether the engine is located at an area source or major source, and whether the engine is a compression ignition or a spark ignition engine. Spark ignition engines are further subdivided by power cycle, two versus four stroke, and whether the engine is rich burn or lean burn.

RICE engines in the NOx SIP Call area are covered by state regulations implementing those requirements. EPA estimated that NOx emissions within the control region were expected to be reduced by about 53,000 tons per 5month ozone season in 2007 from what they would otherwise be without this program. Federal rules affecting RICE included the NESHAP for RICE (40 CFR part 63, Subpart ZZZZ), NSPS for Stationary Spark Ignition IC engines (40 CFR part 60, Subpart JJJJ), and NSPS for Compression Ignition IC engines (40 CFR part 60, Subpart IIII). SI engine operators were affected by the NSPS if the engine was constructed after June 12, 2006, with some of the smaller engines affected by the NSPS 1-3 years later. The recommended RICE equipment lifetime is 30 to 40 years depending on web searches. We chose 40 years as a conservative estimate.

The 2011 estimates of the RICE engine average emission rates for lean burn and rich burn engines was developed using the stationary engine manufacturers data submitted to the EPA for the NSPS analysis (Parise, 2005). Emission factors by pollutant for engines 500-1200 horsepower (hp) were used to develop the average emission rates. The analysis was organized this way because lean versus rich burn engine type is such a significant factor in the NOx emissions rate. Any state emission regulations that require stationary RICE engines to achieve emission levels lower than the 2012 NSPS could be included by using lower new source emission ratios that account for the additional emission reductions associated with having more stringent state permit rules. Information is provided for Pennsylvania in Table 4-33. That information shows that the Pennsylvania regulations have different emission standards for lean burn versus rich burn engines, and that the emission limits also vary by engine size (100-500 hp or greater than 500 hp). While some of the newer RICE SCCs (oil and gas sector in particular) allow states to indicate whether engines are lean versus rich burn, some SCCs lump these two together. None of the RICE point source SCCs have information about engine sizes. However, the EPA RIA for the RICE NSPS and NESHAP analysis (RTI, 2007) provides a table that shows the NOx (CO, NMHC and HAP emission estimates are provided as well) emissions in 2015 by engine size, along with engine populations by size. In the future, more rigorous analysis can use this table to develop computations of weighted average emission reductions by rated hp to state regulations like Pennsylvania's.

Table 4-33. RICE NSPS Analysis and resulting 2011v6.2 emission rates used to compute controls

Engine type & fuel	**Max Engine Power**	**Geographic Applicability**	**Emission standards g/HP-hr**		
			NOx	**CO**	**VOC**
2011 pop lean burn	500-1200 hp		1.65	2.25	0.7
2011 pop rich burn	500-1200 hp		14.5	8	0.45
Non-Emerg. SI NG and Non-E. SI Lean Burn LPG (except LB 500≤HP<1,350)	HP≥100	2006 NSPS	2.0	4.0	1.0
Non-Emerg. SI NG and Non-E. SI Lean Burn LPG (except LB 500≤HP<1,350)	HP≥100	2012 NSPS	1.0	2.0	0.7
	HP≥100	PA (Previous GP-5)	2.0	2.0	2.0
New NG Lean Burn	100<HP<500	PA (New GP-5)	1.0	2.0	0.7
New NG Lean Burn	HP >500	PA (New GP-5)	0.5	2.0	0.25
New NG Rich Burn	100<HP<500	PA (New GP-5)	0.25	0.3	0.2
New NG Rich Burn	HP >500	PA (New GP-5)	0.2	0.3	0.2
	HP≥100	Maryland	1.5		
	HP>7500	Colorado	1.2 - 2		
		Wyoming	None	None	None
Notes: the above table compares the criteria pollutant emission standards from the recent NSPS with the emission limits from selected states for stationary IC engines to determine whether future year emission rates are likely to be significantly lower than for the existing engine population. States in the NOx SIP Call region instituted NOx emission limits for large engines well before 2011. Most of the values in the above table come from an analysis posted on the PA DEP website. The state emission limits listed above are those in place prior to 2011. Some states (like PA) have instituted tougher RICE emission limits for new and modified engines more recently.					
Note 2: Wyoming exempts all but the largest RICE engines from emission limits.					
Note 3: PA has had a size limit for new RICE engines of 1500 hp until recently (i.e., not engines bigger than 1500 hp can be installed). Their new General Permit-5 removed the engines size cap, but requires new or modified larger engines to be cleaner (i.e., has emission limits lower than the NSPS). PA expects that the new emission limits will result in an increase in larger engines being installed, and bringing the average emission rate much lower than it is currently.					
New source Emissions Rate (Fn): Controls % =100 * (1-Fn)			**NOx**	**CO**	**VOC**

Engine type & fuel	Max Engine Power	Geographic Applicability	Emission standards g/HP-hr		
			NOx	CO	VOC
Pennsylvania	NG-Comb. LB & RB		0.175	0.575	0.113
All other states	NG-Comb. LB & RB		0.338	0.569	1.278
Pennsylvania	NG-lean burn		0.250	1.000	0.125
All other states	NG-lean burn		0.606	0.889	1.000
Pennsylvania	NG-rich burn		0.100	0.150	0.100
All other states	NG-rich burn		0.069	0.250	1.556

We applied NSPS reduction for lean burn, rich burn and "combined" (not specified). We also computed scaled-down (less-stringent) NSPS controls for SCCs that were "IC engines + Boilers" because boiler emissions are not subject to RICE NSPS. For these SCCs, we used the 2011NEIv2 point inventory to aggregate eligible (fuel and type) boiler and IC engine emissions for each pollutant. We found that for CI engines, almost all emissions were boiler-related; therefore, there are no CI engine RICE NSPS reductions for "IC engines + Boilers." For SI engines, we found that approximately 9 percent of NOx, 10 percent of CO and 19 percent of VOC "IC engines + Boilers" were IC engines; these splits were then applied to the NSPS reductions in Table 4-33. Finally, we limited RICE NSPS-eligible sources (SCCs) to those that have at least 100 tons nationally for NOx, CO or VOC, and ignored resulting controls that were under 1 percent.

Pennsylvania DEP staff note that until recently they have limited RICE engines to a maximum of 1500 hp. That cap is lifted under the new General Permit-5 regulations. With that cap lifting, Pennsylvania expects that new applications will choose to install larger engines which have lower emission limits. However, that potential effect will be difficult to capture with no information about how this might occur. These controls were then plugged into *Equation 2* (see Section 4.2.4) as a function of the projection factor. Resulting controls greater than or equal to 1 percent were retained. Note that where new emissions factors >=1.0 (uncontrolled, as represented by red cells at the bottom of Table 4-33), no RICE NSPS controls were computed. National RICE NSPS reductions from projected pre-NSPS 2023 inventory is shown in Table 4-34. This table reflects the impacts of both the MARAMA and non-MARAMA packets.

Table 4-34. National by-sector reductions from RICE NSPS controls for 2023en (tons)

Pollutant	Year	Nonpoint Oil & Gas (np_oilgas)	Point Oil & Gas (pt_oilgas)	Nonpoint (nonpt)	Point (ptnonipm)	Total NSPS reductions	Pre-NSPS total emissions	NSPS % reduction
CO	2023	37,637	45,012	2,278	1,344	86,270	396,892	22%
NOX	2023	42,141	108,925	3,903	2,027	156,997	574,683	27%
VOC	2023	2,641	689	0	2	3,332	5,528	60%

4.2.4.4 ICI boilers (nonpt, ptnonipm, pt_oilgas)

Packets:

CONTROL_2011v6.2_20xx_BoilerMACT_POINT_v2_30jan2015_v0.txt
CONTROL_2011v6.2_20xx_BoilerMACT_NONPT_08jan2015_11jan2016_nf_v1.txt
NCDAQ_CONTROL_2011v6_2_2017_BoilerMACT_POINT_revised_07jan2016_v0.txt
BETA_Controls_BOILER_MACT_24aug2016.csv (MARAMA)

The Industrial/Commercial/Institutional Boilers and Process Heaters MACT Rule, hereafter simply referred to as the "Boiler MACT," was promulgated on January 31, 2013, based on reconsideration. Background information on the Boiler MACT can be found at: https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-energy-engines-and. The Boiler MACT promulgates national emission standards for the control of HAPs (NESHAP) for new and existing industrial, commercial, and institutional (ICI) boilers and process heaters at major sources of HAPs. The expected cobenefit for CAPs at these facilities is significant and greatest for SO_2 with lesser impacts for direct PM, CO and VOC. These packets address only the expected cobenefits to existing ICI boilers. MARAMA supplied their own control packet that covers the MACT Rule impacts for their states.

Boiler MACT reductions were computed from a non-NEI database of ICI boilers. As seen in the Boiler MACT Reconsideration RIA (see docket item EPA-HQ-OAR-2002-0058-3876 on http://regulations.gov, EPA 2011c), this Boiler MACT Information Collection Request (ICR) dataset computed over 558,000 tons of SO_2 reductions by year 2015. However, the Boiler MACT ICR database and reductions are based on the assumption that if a unit *could* burn oil, it *did* burn oil, and often to capacity. With high oil prices and many of these units also able to burn cheaper natural gas, the 2011NEIv2 inventory has a lot more gas combustion and a lot less oil combustion than the boiler MACT database. For this reason, the EPA decided to target units that potentially could be subject to the Boiler MACT and compute preliminary reductions for several CAPs prior to building a control packet.

Step 1: Extract facilities/sources potentially subject to Boiler MACT

This step is only applicable to point inventory sources. The EPA did not attempt to map each ICR unit to the NEI units, instead choosing to use a more general approach to extract NEI sources that would be potentially subject to, and hence have emissions reduced by the Boiler MACT. The NEI includes a field that indicates whether a facility is a major source of HAPs and/or CAPs. This field in our FF10 point inventory modeling file is called "FACIL_CATEGORY_CODE" and the possible values for that field are shown in Table 4-35.

Table 4-35. Facility types potentially subject to Boiler MACT reductions

Code	Facility Category	Subject to Boiler MACT?	Description
CAP	CAP Major	N	Facility is Major based upon 40 CFR 70 Major Source definition paragraph 2 (100 tpy any CAP. Also meets paragraph 3 definition, but NOT paragraph 1 definition).
HAP	HAP Major	Y	Facility is Major based upon only 40 CFR 70 Major Source definition paragraph 1 (10/25 tpy HAPs).
HAPCAP	HAP and CAP Major	Y	Facility meets both paragraph 1 and 2 of 40 CFR 70 Major Source definitions (10/25 tpy HAPs and 100 tpy any CAP).
HAPOZN	HAP and O3 n/a Major	Y	Facility meets both paragraph 1 and 3 of 40 CFR 70 Major Source definitions (10/25 tpy HAPs and Ozone n/a area lesser tons for NO_X or VOC).
NON	Non-Major	N	Facility's Potential to Emit is below all 40 CFR 70 Major Source threshold definitions without a FESOP.
OZN	O3 n/a Major	N	Facility is Major based upon only 40 CFR 70 Major Source definition paragraph 3 (Ozone n/a area lesser tons for NO_X or VOC).
SYN	Synthetic non-Major	N	Facility has a FESOP which limits its Potential To Emit below all three 40 CFR 70 Major Source definitions.
UNK	Unknown	N	Facility category per 40 CFR 70 Major Source definitions is unknown.

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Because the Boiler MACT rule applies to only major sources of HAPs, the EPA restricted the universe of facilities potentially subject to the Boiler MACT to those classified as HAP major or unknown (UNK). The third column indicates whether the facility was a candidate for extraction as being potentially subject to the Boiler MACT.

Step 2: Merge control information with 2011 NEI and apply state NODA comments

The EPA analyzed the SCCs in the OTC 2007 inventories and tweaked the SCC mapping of these ICI boiler adjustments to map to those in the 2011 NEI point and nonpoint inventory with non-zero emissions. The EPA also removed some duplicate and incorrect mappings and expanded the SCC mapping in some cases to SCCs that were in the NEI, but not the OTC inventory (and thus missing from the analysis).

Some states commented on the 2011v6.0 ICI boiler controls via the 2018 NODA (docket # EPA-HQ-OAR-2013-0809 on http://www.regulations.gov). Wisconsin provided alternative SO_2, VOC and HCl controls for stoker and pulverized coal fueled units. The national-level and Wisconsin-specific ICI boiler adjustments, applied at the unit-level for point sources and by SCC (and state for Wisconsin) are provided in Table 4-36; note that we applied the same national-level adjustments to CO, NOx and PM for coal units in Wisconsin. New York and New Jersey, via the MARAMA comment/data to the 2018 NODA, provided boiler rule NOx reductions that also supersede these nationally-applied factors. The New Jersey and New York factors are provided in Table 4-37; note that New Jersey controls apply only to nonpoint sources and that New York controls vary by fuel for point sources.

Table 4-36. National-level, with Wisconsin exceptions, ICI boiler adjustment factors by base fuel type

	Default % Reduction (Adjustments)					
Unit/Fuel Type	**CO**	**NOX**	**PM**	**SO2**	**VOC**	**HCl**
Stoker Coal	98.9	70.7	96	97.4	98.9	95
Pulverized Coal	98.9	60.6	72.2	73	98.9	95
Residual Oil	99.9	57	92.4	97.1	99.9	95
Distillate Oil	99.9	38.8	68.4	99.9	99.9	88.6
Wisconsin: Stoker Coal	98.9	70.7	96	30	0	45
Wisconsin: Pulverized Coal	98.9	60.6	72.2	30	0	45

Table 4-37. New York and New Jersey NO_X ICI Boiler Rules that supersede national approach

NJ and NY Boiler Rule controls	**NOX % Reduction**
New Jersey Small Boiler Rule (nonpoint only): Default for Distillate, Residual, natural gas and LPG	25
New York Small Boiler Rule (nonpoint only): Default for Distillate, Residual, natural gas and LPG	10
NY Boiler Rule: Industrial /Distillate Oil /< 10 Million Btu/hr	10
NY Boiler Rule: Industrial /Residual Oil /10-100 Million Btu/hr	33.3
NY Boiler Rule: Electric Gen /Residual Oil /Grade 6 Oil: Normal Firing	40
NY Boiler Rule: Electric Gen /Natural Gas /Boilers, < 100 Million Btu/hr except Tangent	50
NY Boiler Rule: Electric Gen /Natural Gas /Boilers, 100 Million Btu/hr except Tangent	60
NY Boiler Rule: Industrial /Bitum Coal /Cyclone Furnace	66.7
NY Boiler Rule: Industrial /Natural Gas /> 100 Million Btu/hr	70
NY Boiler Rule: Electric Gen /Bituminous Coal /Pulverized Coal: Dry Bottom	73.3

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The impacts of these ICI boiler reductions are provided in Table 4-38. This table reflects the impacts of both the MARAMA and non-MARAMA packets. Overall, the CO and $PM_{2.5}$ reductions are reasonably close to the year-2015 expected reductions in the Boiler MACT Reconsideration RIA (see docket item EPA-HQ-OAR-2002-0058-3876 on http://regulations.gov). It is worth noting that the SO_2 reductions in the preamble for the Boiler MACT Reconsideration (76 FR 80532; https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters) were estimated at 442,000 tons; the additional SO_2 reductions in the reconsideration are from an additional co-benefit from more stringent HCl controls. The 2011NEIv2 SO_2 emissions are actually less than the estimated Boiler MACT reductions, likely a result of numerous units undergoing fuel switching from coal or oil to natural gas.

Table 4-38. Summary of ICI Boiler reductions for 2023en

Year	Pollutant	Emissions Eligible for Control	Controlled (Final) Emissions	Reductions (tons)	% Reductions
CO	2023	20,568	3,760	16,808	81.7%
NOX	2023	65,430	31,226	34,204	52.3%
PM10	2023	9,050	2,140	6,910	76.4%
PM2.5	2023	6,540	1,601	4,939	75.5%
SO2	2023	142,660	25,677	116,983	82.0%
VOC	2023	1,222	187	1,035	84.7%

4.2.4.5 Fuel sulfur rules (nonpt, ptnonipm, pt_oilgas)

Packet:

"CONTROL_2011v6.2_20xx_Fuel_Sulfur_Rules_09jan2015_v0.txt"
"BETA_Controls_MANEVU_SULFUR_2016_08_24.csv" (MARAMA)

Fuel sulfur rules, based on web searching and the 2011 emissions modeling NODA comments, are currently limited to the following states: Connecticut, Delaware, Maine, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island and Vermont. The fuel limits for these states are incremental starting after year 2012, but are fully implemented by July 1, 2018, in all of these states.

A summary of all fuel sulfur rules provided back to the EPA by the 2011 emissions modeling NODA comments is provided in Table 4-39. State-specific control factors were computed for distillate, residual and #4 fuel oil using each state's baseline sulfur contents and the sulfur content in the rules. For most states, the baseline sulfur content was 3,000 ppm (0.3 percent) for distillate oil, and 2.25 percent for residual and #4 oil. However, many states had lower baseline sulfur contents for residual oil, which varied by state and county. The SRA used state- or county-specific baseline residual oil sulfur contents to calculate a state- or county-specific control factors for residual oil (SRA, 2014).

A summary of the sulfur rules by state, with emissions reductions is provided in Table 4-40. This table reflects the impacts of the MARAMA packet only, as these reductions are not estimated in non-MARAMA states. Most of these reductions (98+ percent) occur in the nonpt sector; a small amount of reductions occur in the ptnonipm sector, and a negligible amount of reductions occur in the pt_oilgas sector. Note that these reductions are based on intermediate 2023 inventories, those grown from 2011 to the specific future years.

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Table 4-39. State Fuel Oil Sulfur Rules data provided by MANE-VU

State	Reference
Connecticut	Section 22a-174-19a. Control of sulfur dioxide emissions from power plants and other large stationary sources of air pollution: Distillate and Residual: 3000 ppm effective April 15, 2014. Section 22a – 174 - 19b. Fuel Sulfur Content Limitations for Stationary Sources (except for sources subject to Section 22a-174-19a). Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 Residual: 1.0% effective July 1, 2014; 0.3% effective July 1, 2018 Connecticut General Statute 16a-21a. Sulfur content of home heating oil and off-road diesel fuel. Number 2 heating oil and off-road diesel fuel: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 See: http://www.ct.gov/deep/cwp/view.asp?a=2684&Q=322184&deepNav_GID=1619
Delaware	1108 Sulfur Dioxide Emissions from Fuel Burning Equipment Distillate: 15 ppm effective July 1, 2017 Residual: 0.5% effective July 1, 2017 #4 Oil: 0.25% effective July 1, 2017 See: http://regulations.delaware.gov/AdminCode/title7/1000/1100/1108.shtml
Maine	Chapter 106: Low Sulfur Fuel Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 Residual: 0.5% effective July 1, 2018 See: http://www.mainelegislature.org/legis/bills/bills_124th/billpdfs/SP062701.pdf.
Massachusetts	310 CMR 7.05 (1)(a)1: Table 1 : Sulfur Content Limit of Liquid Fossil Fuel Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 Residual: 1.0% effective July 1, 2014; 0.5% effective July 1, 2018 See: http://www.mass.gov/eea/docs/dep/service/regulations/310cmr07.pdf
New Jersey	Title 7, Chapter 27, Subchapter 9 Sulfur in Fuels Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2016 Residual: 0.5% or 0.3%, depending on county, effective July 1, 2014 #4 Oil: 0.25% effective July 1, 2014 See: http://www.nj.gov/dep/aqm/rules27.html
New York	Subpart 225-1 Fuel Composition and Use - Sulfur Limitations Distillate: 15 ppm effective July 1, 2016 Residual: 0.3% in New York City effective July 1, 2014; 0.37% in Nassau, Rockland and Westchester counties effective July 1, 2014; 0.5% remainder of state effective July 1, 2016 See: http://www.nyc.gov/html/dep/html/news/dep_stories_p3-109.shtml and http://green.blogs.nytimes.com/2010/07/20/new-york-mandates-cleaner-heating-oil/?_r=1 and http://switchboard.nrdc.org/blogs/rkassel/governor_paterson_signs_new_la.html
Pennsylvania	§ 123.22. Combustion units Distillate: 500 ppm effective July 1, 2016 Residual: 0.5% effective July 1, 2016 #4 Oil: 0.25% effective July 1, 2016 See: http://www.pacode.com/secure/data/025/chapter123/s123.22.html
Rhode Island	Air Pollution Control Regulations No. 8 Sulfur Content of Fuels Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 Residual: 0.5% effective July 1, 2018 See: http://www.dem.ri.gov/pubs/regs/regs/air/air08_14.pdf
Vermont	5-221(1) Sulfur Limitations in Fuel Distillate: 500 ppm effective July 1, 2014; 15 ppm effective July 1, 2018 Residual: 0.5% effective July 1, 2018 #4 Oil: 0.25% effective July 1, 2018 See: http://www.epa.gov/region1/topics/air/sips/vt/VT_Section5_221.pdf

Table 4-40. Summary of fuel sulfur rule impacts on SO_2 emissions for 2023en

Year	Emissions Eligible for Control	Controlled (Final) Emissions	Reductions	% Reductions
2023	90,764	10,035	80,729	88.9%

4.2.4.6 Natural gas turbines NOx NSPS (ptnonipm, pt_oilgas)

Packet:
"CONTROL_2011v6.2_2025_NOX_GasTurbines_16dec2014_v0.txt"
"BETA_Controls_GasTurbines_NSPS_2023_30jul2016.csv" (MARAMA)

These controls were generated based on examination of emission limits for stationary combustion turbines that are not in the power sector. In 2006, the EPA promulgated standards of performance for new stationary combustion turbines in 40 CFR part 60, subpart KKKK. The standards reflect changes in NOx emission control technologies and turbine design since standards for these units were originally promulgated in 40 CFR part 60, subpart GG. The 2006 NSPSs affecting NOx and SO_2 were established at levels that bring the emission limits up-to-date with the performance of current combustion turbines. Stationary combustion turbines were also regulated by the NOx SIP (State Implementation Plan) Call, which required affected gas turbines to reduce their NOx emissions by 60 percent.

Table 4-41 compares the 2006 NSPS emission limits with the NOx RACT regulations in selected states within the NOx SIP Call region. The map showing the states and partial-states in the NOx SIP Call Program can be found at: http://www3.epa.gov/airmarkets/progress/reports/program_basics.html. We assigned only those counties in Alabama, Michigan and Missouri as NOx SIP call based on the map on page 8. The state NOx RACT regulations summary (Pechan, 2001) is from a year 2001 analysis, so some states may have updated their rules since that time.

Table 4-41. Stationary gas turbines NSPS analysis and resulting emission rates used to compute controls

NOx Emission Limits for New Stationary Combustion Turbines				
Firing Natural Gas	**<50 MMBTU/hr**	**50-850 MMBTU/hr**	**>850 MMBTU/hr**	
Federal NSPS	100	25	15	ppm
State RACT Regulations	**5-100 MMBTU/hr**	**100-250 MMBTU/hr**	**>250 MMBTU/hr**	
Connecticut	225	75	75	ppm
Delaware	42	42	42	ppm
Massachusetts	65*	65	65	ppm
New Jersey	50*	50	50	ppm
New York	50	50	50	ppm
New Hampshire	55	55	55	ppm
* Only applies to 25-100 MMBTU/hr				
Notes: The above state RACT table is from a 2001 analysis. The current NY State regulations have the same emission limits.				
	New source emission rate (Fn)		**NOx ratio**	**Control (%)**
NOx SIP Call states plus CA	= 25 / 42 =		0.595	40.5%
Other states	= 25 / 105 =		0.238	76.2%

Regarding stationary gas turbine lifetimes, the IPM financial modeling documentation lists the book life of combustion turbines as 30 years, with a debt life of 15 years, and a U.S. MACRS Depreciation Schedule of 15 years (EPA, 2013). This same documentation lists the book life of nuclear units at 40 years. IPM uses a 60-year lifetime for nuclear units in its simulations of unit retirements. Using the same relationship between

estimated lifetime and book life for nuclear units of 1.5, the estimated lifetime for a combustion turbine would be 45 years. This is the same as an annual retirement rate of 2.2 percent.

For projection factor development, the existing source emission ratio was set to 1.0 for combustion turbines. The new source emission ratio for the NOx SIP Call states and California is the ratio of state NOx emission limit to the Federal NSPS. A complicating factor in the above is the lack of size information in the stationary source SCCs. Plus, the size classifications in the NSPS do not match the size differentiation used in state air emission regulations. We accepted a simplifying assumption that most industrial applications of combustion turbines are in the 100-250 MMBtu/hr size range, and computed the new source emission rates as the NSPS emission limit for 50-850 MMBtu/hr units divided by the state emission limits. We used a conservative new source emission ratio by using the lowest state emission limit of 42 ppmv (Delaware). This yields a new source emission ratio of 25/42, or 0.595 (40.5 percent reduction) for states with existing combustion turbine emission limits. States without existing turbine NO_x limits would have a lower new source emission ratio -the uncontrolled emission rate (105 ppmv via AP-42) divided into 25 ppmv = 0.238 (76.2 percent reduction). This control was then plugged into *Equation 2* (see Section 4.2.4) as a function of the year-specific projection factor. Resulting controls greater than or equal to 1 percent were included in our projections. National Process Heaters NSPS reductions from projected pre-NSPS 2023 inventory are shown in Table 4-42. This table reflects the impacts of both the MARAMA and non-MARAMA packets.

Table 4-42. National by-sector 2023en NO_X reductions from Stationary Natural Gas Turbine NSPS controls

Sector	Pre-NSPS Emissions	NSPS Reductions	NSPS % Reductions
Non-EGU Point (ptnonipm)	15,109	4,070	27%
Point Oil & Gas (pt_oilgas)	74,020	23,448	32%
Total	89,129	27,518	31%

4.2.4.7 Process heaters NOx NSPS (ptnonipm, pt_oilgas)

Packet:
"CONTROL_2011v6.2_2025_NOX_Process_heaters_09dec2014_v0.txt"
"BETA_Controls_ProcessHeaters_NSPS_2023_30jul2016.csv" (MARAMA)

Process heaters are used throughout refineries and chemical plants to raise the temperature of feed materials to meet reaction or distillation requirements. Fuels are typically residual oil, distillate oil, refinery gas, or natural gas. In some sense, process heaters can be considered as emission control devices because they can be used to control process streams by recovering the fuel value while destroying the VOC. The criteria pollutants of most concern for process heaters are NOx and SO_2.

In 2011, process heaters have not been subject to regional control programs like the NOx SIP Call, so most of the emission controls put in-place at refineries and chemical plants have resulted from RACT regulations that were implemented as part of SIPs to achieve ozone NAAQS in specific areas, and refinery consent decrees. The boiler/process heater NSPS established NOx emission limits for new and modified process heaters. These emission limits are displayed in Table 4-43.

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In order to develop a relationship between the typical process heater emission rates in 2011 compared with what the NSPS will require of new and modified sources, an analysis of the materials in the EPA docket (EPA-HQ-OAR-2007-0011) for the NSPS was performed. This docket contained an EPA memorandum that estimated the NOx emissions impacts for process heaters. Table 1 in that memo titled, "Summary of Representative Baseline NOx Concentrations for Affected Process Heaters," analysis can be used to establish an effective 2011 process heater NOx emission rate, although the information that EPA used in the revised NOx impact estimates probably uses data from a few years before 2011. It is likely that the data used are representative of 2011 emissions because the only wide-ranging program that has affected process heater emission rates recently have been consent decrees, and the emission reductions associated with these agreements should have been achieved before 2011. However, the compliance schedules are company-specific, and differ by company, so it is difficult to make overarching conclusions about when compliance occurred.

Table 4-43. Process Heaters NSPS analysis and 2011v6.2 new emission rates used to compute controls

NO_X emission rate Existing (Fe)	**Fraction at this rate**		
PPMV	**Natural Draft**	**Forced Draft**	**Average**
80	0.4	0	
100	0.4	0.5	
150	0.15	0.35	
200	0.05	0.1	
240	0	0.05	
Cumulative, weighted: Fe	104.5	134.5	**119.5**
NSPS Standard	40	60	
New Source NO_X ratio (Fn)	0.383	0.446	**0.414**
NSPS Control (%)	61.7	55.4	**58.6**

The EPA states that because it "does not have much data on the precise proportion of process heaters that are forced versus natural draft, so the nationwide impacts are expressed as a range bounded by these two scenarios." (Scenario 1 assumes all of the process heaters are natural draft process heaters and Scenario 2 assumes all of the process heaters are forced draft process heaters.)

For computations, the existing source emission ratio (Fe) was set to 1.0. The computed (average) NO_x emission factor ratio for new sources (Fn) is 0.41 (58.6 percent control). The retirement rate is the inverse of the expected unit lifetime. There is limited information in the literature about process heater lifetimes. This information was reviewed at the time that the Western Regional Air Partnership (WRAP) developed its initial regional haze program emission projections, and energy technology models used a 20-year lifetime for most refinery equipment. However, it was noted that in practice, heaters would probably have a lifetime that was on the order of 50 percent above that estimate. Therefore, a 30-year lifetime was used to estimate the effects of process heater growth and retirement. This yields a 3.3 percent retirement rate. This control was then plugged into *Equation 2* (see Section 4.2.4) as a function of the year-specific projection factor. Resulting controls greater than or equal to 1 percent were retained. National Process Heaters NSPS reductions from projected pre-NSPS 2023 inventory are shown in Table 4-44. This table reflects the impacts of both the MARAMA and non-MARAMA packets.

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Table 4-44. National by-sector NO_X reductions from Process Heaters NSPS controls for 2023en

Sector	Pre-NSPS Emissions	NSPS Reductions	NSPS % Reductions
Non-EGU Point (ptnonipm)	72,798	20,151	28%
Point Oil & Gas (pt_oilgas)	7,352	1,828	25%
Total	80,149	21,979	27%

4.2.4.8 Arizona regional haze controls (ptnonipm)

Packet:

"CONTROL_2011v6.2_20xx_AZ_Regional_Haze_PT_24feb2015_v0.txt"

U.S. EPA Region 9 provided regional haze FIP controls for a few industrial facilities. Information on these controls are available in the *Federal Register* (EPA-R09-OAR-2013-0588; FRL-9912-97-OAR) at http://www.federalregister.com. These non-EGU controls have implementation dates between September 2017 and December 2018 and, therefore, do not reduce emissions in year 2017 projections. Year 2025 emissions are reduced at 5 smelter and cement units: NOx by 1,722 tons and SO_2 by 26,423 tons.

4.2.4.9 CISWI (ptnonipm)

Packet:

"CONTROL_CISWI_2011v6_22nov2013_v0.txt"

On March 21, 2011, the EPA promulgated the revised NSPS and emission guidelines for Commercial and Industrial Solid Waste Incineration (CISWI) units. This was a response to the voluntary remand that was granted in 2001 and the vacatur and remand of the CISWI definition rule in 2007. In addition, the standards re-development included the 5-year technology review of the new source performance standards and emission guidelines required under Section 129 of the Clean Air Act. The history of the CISWI implementation is documented here: https://www.epa.gov/stationary-sources-air-pollution/commercial-and-industrial-solid-waste-incineration-units-ciswi-new. Baseline and CISWI rule impacts associated with the CISWI rule are documented here: https://www.regulations.gov/document?D=EPA-HQ-OAR-2003-0119-2559. The EPA mapped the units from the CISWI baseline and controlled dataset to the 2011 NEI inventory and because the baseline CISWI emissions and the 2011 NEI emissions were not the same, the EPA computed percent reductions such that our future year emissions matched the CISWI controlled dataset values. CISWI controls are applied in Arkansas and Louisiana only, totaling 3,100 and 3,552 tons of SO_2 reductions in years 2017 and 2025 respectively. The reductions are greater in year 2025 because they are applied to year-specific projected (grown) emissions.

4.2.4.10 Petroleum Refineries: NSPS Subpart Ja (ptnonipm)

Packets:

"CONTROL_2011v6_3_2017_NSPS_Subpart_JA_07aug2017_v0"

On June 24, 2008, EPA issued final amendments to the Standards of Performance for Petroleum Refineries. This action also promulgated separate standards of performance for new, modified, or reconstructed process units after May 14, 2007 at petroleum refineries. The final standards for new process units included emissions limitations and work practice standards for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, and sulfur recovery plants. In 2012, EPA finalized the rule after some

amendments and technical corrections. See https://www.epa.gov/stationary-sources-air-pollution/petroleum-refineries-new-source-performance-standards-nsps-40-cfr for more details on NSPS – 40 CFR 60 Subpart Ja. These NSPS controls were implemented in the 2023en case in a CONTROL packet (CONTROL_2011v6_3_2017_NSPS_Subpart_JA_07aug2017_v0) that was applied to petroleum refineries in the ptnonipm sector. Table 4-39 below reflects the impacts of these NSPS controls on the ptnonipm sector.

Table 4-45. National emissions reductions from Petroleum Refineries NSPS controls for 2023en.

Year	Pollutant	Emissions Eligible for Control	Controlled (Final) Emissions	Reductions (tons)	% Reductions
NOX	2023	10,353	7,696	2,657	26%
SO2	2023	24,709	14,896	9,813	40%
VOC	2023	3,731	682	3,049	82%

4.2.4.11 Data from comments on previous platforms and recent comments (nonpt, ptnonipm, pt_oilgas)

Packets:

"CONTROL_2011v6.2_20xx_State_comments_2018docket_nonpt_15jan2015_v0.txt"
"CONTROL_2011v6_2_20xx_CD_St_com_2018docket_pt_15jan2015_fixed_01sep2015_v0.txt"
"BETA_Controls_STATE_RULES_AND_CONSENT_DECREES_2016_08_11.csv" (MARAMA)
"BETA_Controls_OTC_RULES_2016_08_13.csv" (MARAMA)

All remaining non-EGU point and nonpoint controls are discussed in this section. For the nonpoint sector, these controls are limited to comments/data-responses on the previous emissions modeling platforms, and the 2018 NODA process. For point sources, controls include data from the 2018 NODA process as well as a concatenation of all remaining controls not already discussed. These controls are split into separate packets for point and nonpoint sources.

Nonpoint packet: (CONTROL_2011v6.2_20xx_State_comments_2018docket_nonpt_15jan2015_v0.txt)
This packet contains all nonpoint controls not already discussed in previous sections (e.g., Fuel Sulfur rules, ICI boilers) provided in response to the 2018 NODA, and is restricted to VOC controls for Delaware, Massachusetts, Pennsylvania and Virginia, with the great majority of these controls restricted to Virginia. These VOC controls cover various state programs and rules such as auto refinishing, adhesives and surface coatings. Cumulatively, these VOC controls reduce nonpoint VOC by approximately 3,900 tons in 2017 and 4,100 tons in 2025.

Point packet: CONTROL_2011v6_2_20xx_CD_St_com_2018docket_pt_15jan2015_fixed.txt

This packet contains all point controls not already discussed in previous sections (e.g., Fuel Sulfur rules, ICI boilers). This packet includes new controls information provided in response to the 2018 NODA as well as "legacy" controls from the 2011v6.0 emissions modeling platform from numerous sources such as settlement and consent decree data gathering efforts, comments received during the CSAPR rulemaking process, regional haze modeling, and stack-specific control information provided by TCEQ.

New control information from the 2018 NODA responses is primarily limited to VOC controls from several states: Delaware, Massachusetts, New Jersey, Pennsylvania and Virginia. However, we also received

comments with revised compliance dates, removal of existing control information, and updated controls from local settlements. The CONTROL packet comments field provides information on the source of new control information, where available.

The "old" control information includes information discussed in previous emissions modeling platforms; these CONTROL packet components are discussed in Section 4.2.9 in the 2011v6.1 emissions modeling platform TSD (EPA, 2014b).

Cumulative ptnonipm and pt_oilgas reductions to 2023 pre-controlled (projection factors already applied) from this CONTROL packet are shown in Table 4-46. This table reflects the impacts of both the MARAMA and non-MARAMA packets. In the August, 2016 data provided by MARAMA, impacts from the Pennsylvania RACT regulations were included. The estimated PA RACT NOx reduction for cement kilns, glass melting, and natural gas transmission was approximately 7700 tons. There were six MWC facilities in Pennsylvania be subject to RACT for a total of 19 units. However, these were not adjusted because all but one were found to alrady be emitting at rates under the applicable NOx RACT limit. The one unit that was found to be above the limit was not adjusted due to its small impact of approximately 6 tons. In addition, note that some of the natural gas transmission sources in Pennsylvania were affected by both RACT and the gas turbine NSPS.

Table 4-46. Summary of remaining nonpt, ptnonipm and pt_oilgas reductions for 2023en

Year	Pollutant	Emissions Eligible for Control	Controlled (Final) Emissions	Reductions	% Reductions
2023	CO	5,554	754	4,799	86%
2023	NH3	213	52	161	76%
2023	NOX	96,249	47,796	48,453	50%
2023	PM10	4,055	1,944	2,111	52%
2023	PM2.5	3,643	1,766	1,877	52%
2023	SO2	122,036	25,357	96,679	79%
2023	VOC	30,031	22,954	7,077	24%

For 2023en, additional reductions to ptnonipm sources were made to account for coal mine trucks in Wyoming getting cleaner in future years. The reductions were based on percent reductions to heavy duty offroad construction trucks and are shown in Table 4-47.

Table 4-47. Reductions in Wyoming coal mine trucks in 2023en

Year	Pollutant	Emissions Eligible for Control	Controlled (Final) Emissions	Reductions	% Reductions
2023	CO	17,238	3,475	13,763	78%
2023	NOX	15,808	8,332	7,477	47%
2023	PM10	1,051	240	811	77%
2023	PM2.5	1,024	234	790	77%
2023	SO2	343	208	134	39%
2023	VOC	190	158	31	17%

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4.2.5 Stand-alone future year inventories (nonpt, ptnonipm)

This section discusses future year NEI non-EGU point and nonpoint emission inventories that were not created via CoST strategies/programs/packets. These inventories are either new to the future years because they did not exist in 2011 (e.g., new cement kilns, biodiesel and cellulosic plants), or are a complete replacement to the year 2011 NEI inventory in the case of portable fuel containers. New non-EGU facilities provided by South Carolina via the 2018 NODA on the 2011v6.0 platform were mistakenly omitted from both year 2017 and 2025 emissions modeling processing. Cumulatively, these new facilities would have added approximately 200 tons of NO_x, and under 100 tons of each of the remaining CAPs.

4.2.5.1 Portable fuel containers (nonpt)

Future year inventory: "pfc_2025_2011v6.2_ff10_28jan2015_13sep2016_v2.csv"

The EPA used future-year VOC emissions from Portable Fuel Containers (PFCs) from inventories developed and modeled for EPA's MSAT2 rule (EPA, 2007a). The six PFC SCCs are summarized below (note that the full SCC descriptions for these SCCs include "Storage and Transport; Petroleum and Petroleum Product Storage" as the beginning of the description).

- 2501011011 Residential Portable Fuel Containers: Permeation
- 2501011012 Residential Portable Fuel Containers: Evaporation
- 2501011014 Residential Portable Fuel Containers: Refilling at the Pump: Vapor Displacement
- 2501012011 Commercial Portable Fuel Containers: Permeation
- 2501012012 Commercial Portable Fuel Containers: Evaporation
- 2501012014 Commercial Portable Fuel Containers: Refilling at the Pump: Vapor Displacement

The future-year emissions reflect projected increases in fuel consumption, state programs to reduce PFC emissions, standards promulgated in the MSAT2 rule, and impacts of the RFS2 standards on gasoline volatility. The EPA developed year 2025 PFC emissions that include estimated Reid Vapor Pressure (RVP) and oxygenate impacts on VOC emissions, and more importantly, large increases in ethanol emissions from RFS2. These emission estimates also include gas can vapor displacement, tank permeation and diurnal emissions from evaporation. Because the future year PFC inventories contain ethanol in addition to benzene, the EPA developed a VOC E-profile that integrated ethanol and benzene (see Section 3.2.1.2 of the 2011v6.3 platform TSD for more details). Note that spillage emissions were not projected and were carried forward from 2011. We received projection and control packets from MARAMA in August 2016. We applied these packets to the PFC inventory to obtain year 2023 emissions for the MARAMA states. The names of these packets were the following:

- BETA_Projections_PFC_2023_10aug2016_emf.csv
- BETA_Controls_PFC_28jul2016.csv

A summary of the resulting PFC emissions for 2011 and 2025 (used for 2023) for MARAMA and non-MARAMA states are provided in Table 4-48. Note that for MARAMA states, PFCs were projected from 2011, with separate projections for 2023 and 2028. For non-MARAMA states, the EPA 2025 PFC inventory was used for 2023. Note that the EPA PFC inventory includes ethanol, but MARAMA inventories do not because they were projected from the 2011NEIv2.

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Table 4-48. PFC emissions for 2011 and 2023 [tons]

	MARAMA Emissions		Difference	% Change
	2011	**2023**	**2023**	**2023**
VOC	38,152	12,595	-25,557	-67.0%
Benzene	463	474	10	2.3%

	non-MARAMA Emissions		Difference	% Change
	2011	**2025**	**2025**	**2025**
VOC	160,051	46,498	-113,553	-70.9%
Benzene	323	613	290	89.8%
Ethanol	0	3,294	n/a	

4.2.5.2 Biodiesel plants (ptnonipm)

New Future year inventory: "Biodiesel_Plants_2018_ff10"

The EPA's OTAQ developed an inventory of biodiesel plants for 2018. Plant location and production volume data came from the Tier 3 proposed rule[44,45]. The total volume of biodiesel came from the AEO 2013 early release, 1.3 BG for 2018. To reach the total volume of biodiesel, plants that had current production volumes were assumed to be at 100 percent production and the remaining volume was split among plants with planned production. Once facility-level production capacities were scaled, emission factors based on soybean oil feedstock were applied. These emission factors in Table 4-49 are in tons per million gallons (Mgal) and were obtained from the EPA's spreadsheet model for upstream EISA impacts developed for the RFS2 rule (EPA, 2010a). Inventories were modeled as point sources with *Google Earth* and web searching validating facility coordinates and correcting state-county FIPS.

Table 4-49. Emission Factors for Biodiesel Plants (Tons/Mgal)

Pollutant	Emission Factor
VOC	4.3981E-02
CO	5.0069E-01
NO_X	8.0790E-01
PM_{10}	6.8240E-02
$PM_{2.5}$	6.8240E-02
SO_2	5.9445E-03
NH_3	0
Acetaldehyde	2.4783E-07
Acrolein	2.1290E-07
Benzene	3.2458E-08
1,3-Butadiene	0
Formaldehyde	1.5354E-06

[44] U.S. EPA 2014.Regulatory Impact Analysis for Tier 3 Vehicle Emission and Fuel Standards Program. EPA-420-RD-143-0052.
[45] Cook, R. 2014. Development of Air Quality Reference Case Upstream and Portable Fuel Container Inventories for Tier 3 Final Rule. Memorandum to Docket EPA-HQ-OAR-2010-0162.

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Table 4-50 provides the 2018 biodiesel plant emissions estimates. Since biofuels were not projected to change significantly between 2018 and 2023 the year 2018 inventory was used for year 2023. Emissions in 2011 are assumed to be near zero, and HAP emissions in 2023 are nearly zero. The emission factor for ethanol is 0.

Table 4-50. 2018 biodiesel plant emissions [tons]

Pollutant	2018
CO	649
NO_X	1048
PM_{10}	89
$PM_{2.5}$	89
SO_2	8
VOC	57

4.2.5.3 Cellulosic plants (nonpt)

New Future year inventories:
Primary inventory: "2018_cellulosic_inventory"
New Iowa inventory: "cellulosic_new_Iowa_plants_from2018docket_2011v6.2_ff10_28jan2015"

Development of primary inventory
Depending on available feedstock, cellulosic plants are likely to produce fuel through either a biochemical process or a thermochemical process. The EPA developed county-level inventories for biochemical and thermochemical cellulosic fuel production for 2018 to reflect AEO2013 energy renewable fuel volumes. Emissions factors for each cellulosic biofuel refinery reflect the fuel production technology used rather than the fuel produced. Emission rates in Table 4-51 and Table 4-52 were used to develop cellulosic plant inventories. Criteria pollutant emission rates are in tons per RIN gallon. Emission factors from the cellulosic diesel work in the Tier 3 NPRM were used as the emission factors for the thermochemical plants. Cellulosic ethanol VOC and related HAP emission factors from the Tier 3 NPRM were used as the biochemical VOC and related HAP emission factors. Because the future year cellulosic inventory contains ethanol, a VOC E-profile that integrated ethanol was used; see Section 3.2 of the 2011v6.3 platform TSD for more details.

Plants were treated as area sources spread across the entire area of whatever county they were considered to be located in. Cellulosic biofuel refinery siting was based on utilizing the lowest cost feedstock, accounting for the cost of the feedstock itself as well as feedstock storage and the transportation of the feedstock to the cellulosic biofuel refinery. The total number of cellulosic biofuel refineries was projected using volumes from AEO2013 (early release). The methodology used to determine most likely plant locations is described in Section 1.8.1.3 of the RFS2 RIA (EPA, 2010a). Table 4-53 provides the year 2018 cellulosic plant emissions estimates that were used in this year 2023 modeling platform.

Table 4-51. Criteria Pollutant Emission Factors for Cellulosic Plants (Tons/RIN gallon)

Cellulosic Plant Type	VOC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	NH_3
Thermochemical	5.92E-07	8.7E-06	1.31E-05	1.56E-06	7.81E-07	1.17E-06	1.44E-10
Biochemical	1.82E-06	1.29E-05	1.85E-05	3.08E-06	1.23E-06	6.89E-07	0

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Table 4-52. Toxic Emission Factors for Cellulosic Plants (Tons/RIN gallon)

Plant Type	Acetaldehyde	Acrolein	Benzene	1,3-Butadiene	Formaldehyde	Ethanol
Thermochemical	2.95E-08	1.27E-09	9.61E-10	0	5.07E-09	2.09E-07
Biochemical	3.98E-07	1.11E-08	1.39E-08	0	2.28E-08	6.41E-07

Table 4-53. Cellulosic plant emissions [tons]

Pollutant	Emissions
Acrolein	1
Formaldehyde	3
Benzene	0
Acetaldehyde	15
CO	4,435
Ethanol	106
NH_3	0
NO_X	6,702
PM_{10}	793
$PM_{2.5}$	398
SO_2	596
VOC	302

Development of new Iowa inventory

The Iowa DNR (Department of Natural Resources), via the 2018 NODA comments (see docket # EPA-HQ-OAR-2013-0809 under http://www.regulations.gov), provided information on new cellulosic ethanol capacity information for three facilities. Emissions for these facilities were computed using the emission factors previously discussed in Table 4-51 and Table 4-52. The resulting new facilities and NOx emissions, used for year 2023 are provided in Table 4-54. Note that these facilities are in a nonpoint inventory because latitude-longitude coordinates were not available.

Table 4-54. New cellulosic plants NOx emissions provided by Iowa DNR.

FIPS	County	Facility Name	Approximate Production Capacity (Mgal/yr)	NO_X Emissions
19093	Ida	Quad County Corn Processors' Adding Cellulosic Ethanol (ACE)	2	26
19147	Palo Alto	POET-DSM Project Liberty	25	329
19169	Story	DuPont Cellulosic Ethanol	30	394

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4.2.5.4 New cement plants (nonpt)

Nonpoint Inventories: "cement_newkilns_year_2025_from_ISIS2013_NEI2011v1_NONPOINT_v0.csv"

As discussed in Section 4.2.3.7, the ISMP model, was used to project the cement manufacturing sector to future years. This section covers new ISMP-generated kilns that did not exist in the 2011 NEI. For kilns that were new in 2018, the EPA used two different approaches for modeling. The ISMP model created "generic" kilns in specific geographically strategic locations (counties) to cover the need for increased production/capacity in future years. Because these generic kilns are not permitted and the location in these counties is uncertain, these are modeled at the county-level to avoid placing new large modeled emissions sources into one grid cell. These nonpoint source kilns were then spatially allocated based on industrial land activity in the county.

For all ISMP future year emissions, PM_{10} is assigned as 0.85 of total PM provided by ISMP, and $PM_{2.5}$ is assigned as 0.15 of total PM. New ISMP-generated kilns are assigned as Precalciner kilns (SCC=30500623). While ISMP provides emissions for mercury, the EPA did not retain these in our modeling. Table 4-55 shows the magnitude of the new ISMP-based cement kilns. ISMP-generated kilns as nonpoint sources only.

Table 4-55. ISMP-generated nonpoint cement kiln emissions

Pollutant	Nonpoint Emissions
NO_X	10,255
$PM_{2.5}$	23
SO_2	5,311
VOC	250

4.2.5.5 New units from states (ptnonipm)

The State of Wisconsin Department of Natural Resources and MARAMA provided comments on the NODA for the 2011v6.3 platform that included the suggestion of new units for the ptnonipm sector that will be running by the year 2023 for the states of Wisconsin, Delaware, and West Virginia. The units listed in Table 4-56 have been incorporated into this platform.

File: "2023en_ptnonipm_new_units_state_comments_DE_WV_WI_09aug2017_v0.csv"

Table 4-56. New Non-EGU Point Units for 2023

Facility name	EIS Facility ID	EIS Unit IDs
Ameresco Delaware Energy-Central	16812111	113545813
Ameresco Delaware Energy-Southern	16810211	108718913
CRODA INC.	588911	108721913
PPG Industries, INC., Natrium Plant	4878711	71796413
Union Carbide Corporation	6884411	UCCI_B016, UCCI_B017, UCCI_B018, UCCI_B019, UCCI_B020

Facility name	EIS Facility ID	EIS Unit IDs
Williams Ohio Valley Midstream - Fort Beeler Gas Processing Plant	16886211	110325313, 110325513, 110325613, 110325713, 110325813, 110325913, 110326113, 110326213, 110326413, 110326513, 110326613, 110326713, 110326813, 110326913, 110327013, 110327113, 110327213, 110327313, 110327413
Armstrong World Industries - Millwood Facility	16886111	110321113, 110321313, 110321413, 110321513, 110321613, 110321713, 110321813, 110321913, 110322013, 110322113, 110322213
Williams Ohio Valley Midstream - Moundsville Fractionation Plant	16886311	110327513, 110327813, 110327913, 110328013
Marathon Petroleum - Neal Propane Cavern	16886611	110333413, 110333513, 110333613
Williams Ohio Valley Midstream - Moundsville Fractionation Plant	16886311	110327613, 110327713
Marathon Petroleum - Butane Cavern	16886511	110333113, 110333213, 110333313
Georgia-Pacific Consumer Products LP	4944011	113709613
Proctor & Gamble Paper Products CO	4943711	125438213
Packaging Corporation of America-Tomahawk	4985811	113802813
Expera Specialty Solutions INC	4943911	122251813

4.3 Mobile source projections

Mobile source monthly inventories of onroad and nonroad mobile emissions were created for 2023 using a combination of the MOVES2014a and the NMIM models. The 2023 onroad emissions account for changes in activity data and the impact of on-the-books rules including some of the recent regulations such as the Light Duty Vehicle GHG Rule for Model-Year 2017-2025, and the Tier 3 Motor Vehicle Emission and Fuel Standards Rule (https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3). Local inspection and maintenance (I/M) and other onroad mobile programs are included such as California LEVIII, the National Low Emissions Vehicle (LEV) and Ozone Transport Commission (OTC) LEV regulations (https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-new-motor-vehicles-and-2), local fuel programs, and Stage II refueling control programs. Table 4-1 provides references to many of these programs.

Nonroad mobile emissions reductions for these years include reductions to various nonroad engines such as diesel engines and recreational marine engine types (pleasure craft), fuel sulfur content, and evaporative emissions standards.

Onroad mobile sources are comprised of several components and are discussed in Section 4.3.1. Monthly nonroad equipment mobile emission projections are discussed in Section 4.3.2. Locomotives and CMV projections were discussed in Section 4.2.3.3.

4.3.1 Onroad mobile (onroad)

The onroad emissions for 2023 use the same SMOKE-MOVES system as for the base year (see Section 2.1). Meteorology, speed, spatial surrogates and temporal profiles, representative counties, and fuel months were the same as for 2011. For the 2011v6.3 platform, the EPA developed activity data and emissions factors directly for 2023.

4.3.1.1 Future activity data

Estimates of total national VMT in 2023 came from AEO 2016 (https://www.eia.gov/outlooks/aeo/) transportation projections. Trends were developed by calculating ratios between 2017 AEO and 2023 AEO[46] estimates and applying the trends to the 2017 VMT from the 2011v6.3 emissions platform. In states for which we received 2018 VMT for use in the 2011v6.2 and 2011v6.3 emissions platforms, 2018 state-submitted VMT was projected using AEO trends from 2018 to 2023, rather than from 2017 to 2023. These ratios were developed for light versus heavy duty and for four fuel types: gasoline, diesel, E-85, and CNG. The projection factors, the national 2017 VMT from the 2011v6.3 platform ("VMT 2017") by broad vehicle and fuel type, and the default future VMT ("VMT 2023") are shown in Table 4-57. Note that where states provided 2018 VMT, the 2023 VMT does not exactly equal the 2017 VMT times the ratio.

Table 4-57. Projection factors for 2023 (in millions of miles)[47]

Classification	MOVES source types	VMT 2017	Ratio 2023	VMT 2023
LD gas	11,21,31,32	2,894,984	1.02357	2,958,777
HD gas	42,43,51,52,53,54	22,600	1.10173	25,018
HHD gas	61	835	1.83151	1,528
LD diesel	21,31,32	93,339	2.33508	212,725
HD diesel	41,42,43,51,52,53,54	73,374	1.10235	80,857
HHD diesel	61,62	151,984	1.05092	159,783
Bus CNG	42	480	1.00496	487
LD E-85	21,31,32	14,784	1.16852	17,245
Total	N/A	3,252,378	N/A	3,456,420

In the above table, light duty (LD) includes passenger cars, light trucks, and sometimes motorcycles, heavy duty (HD) includes buses and single unit trucks, and heavy-heavy duty (HHD) includes combination trucks. The specific MOVES source type codes are listed above. These national SCC6 ratios were applied to the 2017ek VMT to create an EPA estimate of 2023 VMT at the county, SCC level.

Two additional steps were incorporated into the VMT projections. First, a set of states provided 2018 VMT projections for use in the 2011v6.2 and 2011v6.3 emissions platforms: Alabama, Connecticut, Georgia, Maine, Maryland, Massachusetts, Michigan, Missouri, Nevada, New York, New Jersey, North Carolina, Utah,

[46] By "2017 AEO" and "2023 AEO," this refers to the AEO2016's estimates of national VMT in those specific calendar years.
[47] Note: The LD ratios were further adjusted to take into account of high vs low growth of human population (discussed below). On average, the LD ratios match those in this table. For the actual VMT, see the inventory packaged with the cases. In addition, areas for which we incorporated state-submitted VMT for 2018 into the 2011v6.3 emissions platform were projected from 2018 to 2023, rather than from 2017.

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Vermont, Virginia, and Wyoming[48]. For these states, 2018 VMT was projected to 2023 using AEO2016-based trends from 2018 to 2023, similarly to how the rest of the country was projected using AEO2016-based trends from 2017 to 2023. This was done so that the 2018-to-2017 backcasting performed in the 2011v6.3 emissions platform, which is based on older AEO estimates (AEO2014), would not affect these new 2023 projections. Second, the EPA adjusted the national LD ratios so that it would reflect regional differences in growth rate. The EPA analyzed LD VMT and corroborated that it had a high correlation with human population. Therefore, if a region has strong human population growth in the future, it will likely have larger VMT growth than the national average. To take account of this spatial difference in growth, the EPA used human population to adjust the national LD VMT growth rate so that on average the growth rate matched the national average, but any specific county growth rate was adjusted by the human population growth for that county:

$$\text{VMTprojFactor}_{s,c} = \text{AEOprojFactor}_{s} \cdot \left(1 + \left(\left(\frac{\text{humanProjFactor}_{c}}{\text{natlhumanProjFactor}}\right) - 1\right)\right)$$

where

- s = source type/fuel
- c = county
- VMTprojFactor = county VMT projection factor (by source/fuel)
- AEOprojFactor = national VMT projection factor from AEO (by source/fuel)
- humanProjFactor = human projection factor for the county (year specific)
- natlhumanProjFactor = national human projection factor (year specific)
- D = damping factor, 0 = no county adjustment, 1 = full county variation

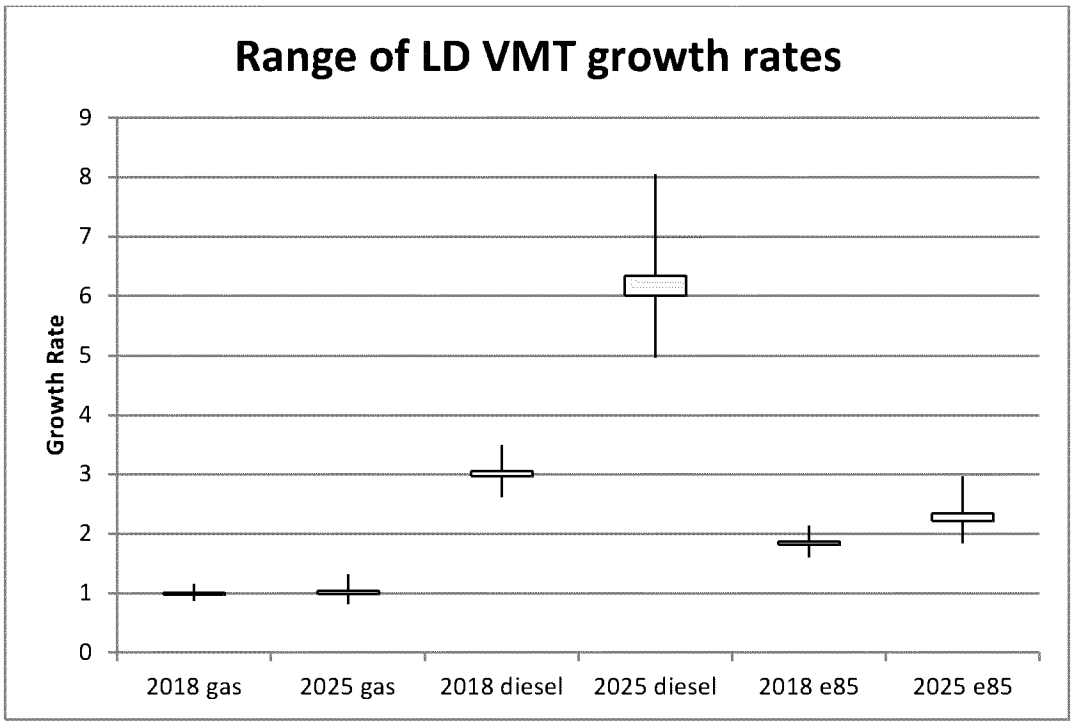
The specific value of D used for EPA projections was 0.5. This was based on an analysis of the growth of LD vehicles over time as compared to human population, which was found to be about 0.5 vehicles per person. The LD growth rates will vary by county, fuel, and year. The range of these growth rates are shown in Figure 4-3.

Vehicle population (VPOP) was developed by creating VMT/VPOP ratios from the 2011NEIv2 VMT and 2011NEIv2 VPOP at the county, fuel and vehicle type (SCC6) level. These ratios were applied to the 2023 VMT to create a 2023 VPOP.

Hoteling (HOTELING) was developed by creating VMT/HOTELING ratios from the 2011 NEIv2 VMT and 2011 NEIv2 HOTELING at the county level. For these ratios, the VMT was limited to combination long-haul trucks (SCC6 220262) on restricted access roads. The HOTELING was the total of auxiliary power units (APU) and extended idle (EXT). These ratios were applied to the 2023 VMT to create a 2023 HOTELING. To get the APU split, 22.62 percent of HOTELING was assumed to be APU in all counties. This is consistent with MOVES2014a default splits for APU for calendar years 2017 and 2025, interpolated to 2023.

[48] For many of these states, we used the county total from the state data and distributed those totals to EPA's SCCs based on default projected VMT. For Michigan, SEMCOG provided the Detroit projections and the rest of the counties came from the state. For Missouri, the state provided the 5 counties around St Louis. For Nevada, the EPA received projections only for Clark County. For Georgia, the state agreed with our default projection method but they wanted to use Georgia-provided human population projections for distributing the LD VMT growth rates to counties. They provided the human population for the 21 Atlanta counties. For the remaining counties, Georgia asked to use EPA defaults.

Figure 4-3. Light Duty VMT growth rates based on AEO2014



4.3.1.2 Set up and run MOVES to create emission factors

Emission factor tables were created by running SMOKE-MOVES using the same procedures and models as described for 2011 (see the 2011NEIv2 TSD and Section 2.1). The same meteorology and the same representative counties were used. Changes between 2011 and future years (2023) are predominantly due to activity data, fuels, national and local rules, and age distributions. Age (i.e., model year) distributions were projected forward using the methodology described in the MOVES activity report (EPA, 2016c), although some states supplied age distributions in their CDBs. Fleet turnover resulted in a greater fraction of newer vehicles meeting stricter emission standards. The similarities and differences between the two runs are described in Table 4-58.

Table 4-58. Inputs for MOVES runs for 2023

Element	2023 MOVES Inputs
Code	MOVES20151201 (MOVES2014a)
Rep. county database	285RepCos2023_M2014_20160520
Default database	movesdb20151028
VMT and VPOP	2023el
Hydrocarbon speciation	CB6v2 done inside MOVES
Fuels	M2014a_fuelsupply AND regioncountytrnoda_20151203
CA LEVIII	ca_standards_SS_20140903 (16 states)

The following states were modeled as having adopted the California LEV III program (see Table 4-59):

Table 4-59. CA LEVIII program states

FIPS	State Name
06	California
09	Connecticut
10	Delaware
23	Maine
24	Maryland
25	Massachusetts
34	New Jersey
36	New York
41	Oregon
42	Pennsylvania
44	Rhode Island
50	Vermont
53	Washington

Fuels were projected into the future using estimates from the AEO2014 (http://www.eia.gov/forecasts/aeo/), release date May 7th 2014, as well as fuel properties changing as part of the Tier 3 Emissions and Fuel Standards Program (https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3). The AEO2014 projection includes market shares of E10, E15, and E85 in 2018, as well as biodiesel market shares up to B5 (note that these values do not assume full implementation of the RFS2 program). The regional fuel properties and renewable volumes in 2011 were projected to 2018 in order to preserve the regional variation present in these fuel supplies, with total fuel volumes aligned to those in the AEO2014.

4.3.1.3 California and Texas adjustments

A set of adjustments were done in SMOKE-MOVES to create 2023 emissions: 1) refueling, and 2) California and Texas emissions.

The first set of adjustment factors was for refueling. This uses the same approach as was used in 2011 (see the Section 2.1 for details) to account for the few counties in Colorado that provided point source gas refueling emissions. These adjustments essentially zero out the MOVES-based gasoline refueling emissions (SCC 2201*62) in these counties so that the point estimates will be used instead and, thus, refueling emissions will not be double-counted.

The second set of adjustment factors was used to incorporate future year emissions provided by California. The same approach as was used in 2011 was used to match the emissions totals provided by CARB. The only differences between the 2011 approach and that applied for 2023 are that the latter uses the 2023 emissions provided by CARB and the 2023 EPA SMOKE-MOVES output to apportion and temporalize the emissions.

The third set of adjustment factors was meant to incorporate emissions provided by Texas. Conceptually, the EPA used the trend of 2017 to 2023 based on the EPA's estimates to project Texas' submitted emissions for 2017. Mathematically, this is equivalent to taking the Texas adjustment factors derived for 2017 and applying them directly to EPA's 2023 run.

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4.3.2 Nonroad Mobile Source Projections (nonroad)

The projection of locomotive and CMV emissions to 2023 is described in Section 4.2.3.3. Most of the remaining sources in the nonroad sector are projected by running the NMIM model with fuels and vehicle populations appropriate to 2023; this section describes the projection of these sources.

The nonroad sector includes monthly exhaust, evaporative and refueling emissions from nonroad engines (not including commercial marine, aircraft, and locomotives) derived from NMIM for all states except California and Texas. NMIM provides nonroad emissions for VOC by three emission modes: exhaust, evaporative and refueling.

With the exception of California and Texas, U.S. emissions for the nonroad sector (defined as the equipment types covered by the NONROAD model) were created using a consistent NMIM-based approach as was used for 2011. Specifically, NMIM version 20090504 utilized NONROAD2008a including future-year equipment population estimates, control programs to the year 2023, and inputs were either state-supplied as part of the 2011NEIv1 and 2011NEIv2 process or national level inputs. Fuels for 2023 were assumed to be E10 everywhere for nonroad equipment. The databases used in the 2023 run were NMIM county database "NCD20160627_nei2023v1" and fuels for the year 2023. The 2023 emissions account for changes in activity data (based on NONROAD model default growth estimates of future-year equipment population) and changes in fuels and engines that reflect implementation of national regulations and local control programs that impact each year differently due to engine turnover.

The version of NONROAD used was the current public release, NR08a, which models all in-force nonroad controls. The represented rules include:

- "Clean Air Nonroad Diesel Final Rule - Tier 4", published June, 2004: https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-emissions-air-pollution-nonroad-diesel.
- Control of Emissions from Nonroad Large Spark-Ignition Engines, and Recreational Engines (Marine and Land-Based), November 8, 2002 ("Pentathalon Rule").
- Small Engine Spark Ignition ("Bond") Rule, October, 2008: https://www.epa.gov/regulations-emissions-vehicles-and-engines/regulations-emissions-small-equipment-tools.

Not included are voluntary local programs such as encouraging either no refueling or evening refueling on Ozone Action Days.

California and Texas nonroad emissions

Similar to the 2011 base year nonroad mobile, NMIM was not used to generate future-year nonroad emissions for California. The CARB-supplied 2023 nonroad annual inventories, which included all CAPs including NH_3, were distributed to monthly emissions values by using monthly temporal profiles assigned by SCC. This is a change from future year California nonroad inventories in prior emissions platforms, in which NMIM monthly inventories were used to compute monthly ratios by county, SCC7, mode and pollutant. See Section 3.2 of the 201v6.3 TSD for details on speciation of California nonroad data. The CARB nonroad emissions include nonroad rules reflected in the December 2010 Rulemaking Inventory (http://www.arb.ca.gov/regact/2010/offroadlsi10/offroadisor.pdf) and those in the March 2011 Rule Inventory, the Off-Road Construction Rule Inventory for "In-Use Diesel."

For Texas, the EPA combined Texas' submitted estimates for 2011 with EPA projections of nonroad emissions into 2023. The EPA used the trend of 2011 to 2023 based on EPA's estimates to project Texas' submitted

emissions for 2011. The projections were based on state-wide SCC7, mode, poll ratios[49] of 2023 NMIM to 2011 NMIM. These ratios were then applied to Texas' submitted 2011 nonroad emissions, which had already been distributed to a monthly inventory to create 2023 monthly nonroad inventories. Please refer to the 2011v6.3 TSD (EPA, 2016) for more information on the year 2011 data obtained from Texas.

4.4 Projections of "Other Emissions": Offshore Category 3 Commercial Marine Vessels and Drilling Platforms, Canada and Mexico (othpt, othar, and othon)

As described in Section 2.5, emissions from Canada, Mexico, and drilling platforms are included as part of three emissions modeling sectors: othpt, othar, and othon. For oil drilling platforms, the EPA used emissions from the 2011NEIv2 point source inventory for 2011 and both future years. The Canadian onroad (othon) and nonroad emissions in othar sector for the 2023en case consisted of year 2025 inventory dataset acquired from Environment Canada (see Tables 5-11 and 5-12). The Canadian point sources in for the othpt sector consisted of year 2025 inventory dataset acquired from Environment Canada (see Table 5-13). Area, nonroad, and point emissions for Mexico are based on the Inventario Nacional de Emisiones de Mexico, 2008 projected to years 2018 and 2025, then interpolated to 2023 (ERG, 2014a). Onroad emissions for Mexico are based on run of MOVES-Mexico for 2023 (ERG, 2016).

[49] These ratios were initially attempted by county/SCC7/mode/pollutant, but due to significantly different distributions of certain source types between the EPA and TCEQ's emissions, this created unreasonable growth in certain areas. The above approach was used except in the following, relatively limited conditions. If a state/SCC7/mode/pollutant was in the EPA's 2023 emissions but not in the EPA's 2011 emissions; 2023 EPA emissions were used in the final inventory. If a state/SCC7/mode/pollutant was in TCEQ's 2011 emissions but was not in EPA's 2023 emissions, then state/SCC3/mode/pollutant ratios were used to project to 2023.

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5 Emission Summaries

The following tables summarize emissions differences between the 2011 evaluation case and the 2023 base case. These summaries are provided at the national level by sector for the contiguous U.S. and for the portions of Canada and Mexico inside the smaller 12km domain (12US2) discussed in Section 0. The afdust sector emissions represent the summaries *after* application of both the land use (transport fraction) and meteorological adjustments; therefore, this sector is called "afdust_adj" in these summaries. The onroad sector totals are post-SMOKE-MOVES totals, representing air quality model-ready emission totals, and include CARB emissions for California and TCEQ emissions for Texas. The cmv sector includes U.S. emissions within state waters only; these extend to roughly 3-5 nautical miles offshore and includes CMV emissions at U.S. ports. "Offshore to EEZ" represents CMV emissions that are within the (up to) 200 nautical mile EEZ boundary but are outside of U.S. state waters along with the offshore oil platform emissions from the NEI. Finally, the "Non-US SECA C3" represents all non-U.S. and non-Canada emissions outside of the (up to) 200nm offshore boundary, including all Mexican CMV emissions. Canadian CMV emissions are included in the othar sector.

National emission totals by air quality model-ready sector are provided for all CAP emissions for the 2011 evaluation case in Table 5-1. The total of all sectors in the 2011 evaluation case are listed as "Con U.S. Total." Table 5-2 provides national emissions totals by sector for CAPs in the 2023 base case.

Table 5-3 provides national-by sector emission summaries for CO for the 2011 evaluation case and 2023 base case, along with percent change from 2011 to 2023. Table 5-4 through Table 5-9 provide the same summaries for NH_3, NOx, $PM_{2.5}$, PM_{10}, SO_2 and VOC, respectively. Note that the same fire emissions are used in all cases. Tables 5-10 through Table 5-12 provide summaries of the Canadian emissions for the entire country used in the 2011 and 2023 base cases for onroad, area, and point source emissions. Tables 5-13 through Table 5-15 provide summaries of the Mexican emissions for the entire country used in the 2011 and 2023 base cases for onroad, area, and point source emissions

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Table 5-1. National by-sector CAP emissions summaries for the 2011 evaluation case

Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
afdust_adj				6,732,941	923,590		
ag		3,515,198					
agfire	1,030,817	3,321	46,035	152,837	101,379	17,755	80,540
cmv_c1c2	58,543	167	288,726	9,712	9,294	6,217	7,696
cmv_c3	11,955	65	125,374	9,946	8,829	84,992	4,888
nonpt	1,645,989	94,242	720,454	491,825	404,258	276,332	3,671,322
np_oilgas	635,942	0	667,068	17,784	16,333	17,232	2,482,590
nonroad	13,951,020	2,627	1,630,301	162,417	154,657	4,031	2,024,419
onroad	25,981,557	120,859	5,708,150	326,900	188,925	28,195	2,713,181
ptfire	20,562,697	329,330	333,398	2,171,987	1,844,263	165,773	4,688,094
ptegu	792,414	25,066	2,096,058	283,066	208,122	4,670,713	38,060
ptnonipm	2,297,549	66,048	1,212,616	477,328	320,816	1,049,374	800,815
pt_oilgas	235,162	5,947	509,856	14,585	13,935	66,577	164,098
rail	122,703	347	791,381	25,898	23,963	7,936	40,851
rwc	2,517,844	19,693	34,436	381,476	381,252	8,954	442,541
Con U.S. Total	**69,844,194**	**4,182,911**	**14,163,853**	**11,258,702**	**4,599,616**	**6,404,080**	**17,159,096**
Offshore to EEZ	176,338	188	904,453	26,401	24,692	139,270	81,713
Non-US SECA C3	16,191	0	191,001	16,228	14,930	120,316	6,878
Canada othafdust				1,192,039	242,374		
Canada othar	2,038,390	338,056	376,758	288,021	157,205	33,464	776,733
Canada othon	1,507,754	6,326	332,349	15,107	5,014	1,270	138,319
Canada othpt	512,629	11,390	231,609	51,137	25,784	522,537	166,284
Canada ptfire_mxca	798,710	13,037	14,048	87,398	73,401	6,481	194,844
Mexico othar	186,575	168,840	183,383	90,691	42,623	10,184	420,637
Mexico othon	1,476,625	2,154	363,342	8,788	3,254	4,432	136,891
Mexico othpt	153,387	3,945	333,368	59,325	45,963	471,847	57,090
Mexico ptfire_mxca	736,810	13,583	31,403	104,125	87,025	6,394	172,196
Non-US Total	**7,603,409**	**557,519**	**2,961,713**	**1,939,261**	**722,265**	**1,316,195**	**2,151,585**

* "Offshore to EEZ" includes both the offshore point emissions, and the "Offshore to EEZ" c3marine emissions.

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Table 5-2. National by-sector CAP emissions summaries for the 2023 base case

Sector	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
afdust_adj				7,498,365	1,009,616		
ag		3,602,039					
agfire	1,030,817	3,321	46,035	152,837	101,379	17,755	80,540
cmv_c1c2	57,696	170	175,059	5,387	5,155	1,987	5,241
cmv_c3	18,569	65	105,567	2,126	1,884	4,824	7,639
nonpt	1,682,696	94,695	733,016	509,892	427,719	96,043	3,452,177
np_oilgas	690,025	0	670,895	24,780	21,786	49,707	2,966,396
nonroad	12,627,798	3,228	856,831	84,153	78,858	2,380	1,177,147
onroad	11,300,137	82,106	1,786,856	232,752	79,527	12,114	987,796
ptfire	20,562,697	329,330	333,398	2,171,987	1,844,263	165,773	4,688,094
ptegu	598,510	29,691	1,051,725	173,057	138,932	1,335,974	32,702
ptnonipm	2,271,136	64,691	1,156,792	473,720	320,641	731,219	782,504
pt_oilgas	231,798	5,917	424,595	15,508	14,847	64,990	177,353
rail	145,627	376	563,382	14,236	13,165	340	21,384
rwc	2,368,934	18,499	34,918	362,897	362,651	7,908	415,748
Con U.S. Total	**53,586,440**	**4,234,128**	**7,939,069**	**11,721,698**	**4,420,423**	**2,491,013**	**14,794,722**
Offshore to EEZ	205,146	188	716,768	9,630	9,125	11,615	92,462
Non-US SECA C3	27,845	0	266,129	10,232	9,371	69,507	11,821
Canada othafdust				1,353,416	270,071		
Canada othar	2,192,418	338,711	238,830	284,898	151,849	22,783	800,300
Canada othon	877,268	5,098	141,282	5,520	5,025	549	47,883
Canada othpt	636,056	15,412	221,980	57,514	31,196	409,282	186,100
Canada ptfire_mxca	798,710	13,037	14,048	87,398	73,401	6,481	194,844
Mexico othar	217,518	167,660	212,147	95,486	46,311	12,159	505,017
Mexico othon	1,543,506	2,853	376,485	9,581	4,586	6,370	143,725
Mexico othpt	199,007	5,669	376,422	71,542	54,940	361,230	80,922
Mexico ptfire_mxca	736,810	13,583	31,403	104,125	87,025	6,394	172,196
Non-US Total	**7,434,284**	**562,210**	**2,595,494**	**2,089,342**	**742,899**	**906,371**	**2,235,269**

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Table 5-3. National by-sector CO emissions (tons/yr) summaries and percent change

Sector	2011 CO	2023 CO	% change 2011 to 2023
afdust_adj	0	0	0%
ag	0	0	0%
agfire	1,030,817	1,030,817	0%
cmv_c1c2	58,543	57,696	-1%
cmv_c3	11,955	18,569	55%
nonpt	1,645,989	1,682,696	2%
np_oilgas	635,942	690,025	9%
nonroad	13,951,020	12,627,798	-9%
onroad	25,981,557	11,300,137	-57%
ptfire	20,562,697	20,562,697	0%
ptegu	792,414	598,510	-24%
ptnonipm	2,297,549	2,271,136	-1%
pt_oilgas	235,162	231,798	-1%
rail	122,703	145,627	19%
rwc	2,517,844	2,368,934	-6%
Con U.S. Total	**69,844,194**	**53,586,440**	**-23%**
Offshore to EEZ	176,338	205,146	16%
Non-US SECA C3	16,191	27,845	72%
Canada othafdust	0	0	0%
Canada othar	2,038,390	2,192,418	8%
Canada othon	1,507,754	877,268	-42%
Canada othpt	512,629	636,056	24%
Canada ptfire_mxca	798,710	798,710	0%
Mexico othar	186,575	217,518	17%
Mexico othon	1,476,625	1,543,506	5%
Mexico othpt	153,387	199,007	30%
Mexico ptfire_mxca	736,810	736,810	0%
Non-US Total	**7,603,409**	**7,434,284**	**-2%**

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Table 5-4. National by-sector NH_3 emissions (tons/yr) summaries and percent change

Sector	2011 NH_3	2023 NH_3	% change 2011 to 2023
afdust_adj	0	0	0%
ag	3,515,198	3,602,039	2%
agfire	3,321	3,321	0%
cmv_c1c2	167	170	2%
cmv_c3	65	65	0%
nonpt	94,242	94,695	0%
np_oilgas	0	0	0%
nonroad	2,627	3,228	23%
onroad	120,859	82,106	-32%
ptfire	329,330	329,330	0%
ptegu	25,066	29,691	18%
ptnonipm	66,048	64,691	-2%
pt_oilgas	5,947	5,917	-1%
rail	347	376	8%
rwc	19,693	18,499	-6%
Con U.S. Total	**4,182,911**	**4,234,128**	**1%**
Offshore to EEZ	188	188	0%
Non-US SECA C3	0	0	0%
Canada othafdust	0	0	0%
Canada othar	338,056	338,711	0%
Canada othon	6,326	5,098	-19%
Canada othpt	11,390	15,412	35%
Canada ptfire_mxca	13,037	13,037	0%
Mexico othar	168,840	167,660	-1%
Mexico othon	2,154	2,853	32%
Mexico othpt	3,945	5,669	44%
Mexico ptfire_mxca	13,583	13,583	0%
Non-US Total	**557,519**	**562,210**	**1%**

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Table 5-5. National by-sector NO_x emissions (tons/yr) summaries and percent change

Sector	2011 NO_x	2023 NO_x	% change 2011 to 2023
afdust_adj	0	0	0%
ag	0	0	0%
agfire	46,035	46,035	0%
cmv_c1c2	288,726	175,059	-39%
cmv_c3	125,374	105,567	-16%
nonpt	720,454	733,016	2%
np_oilgas	667,068	670,895	1%
nonroad	1,630,301	856,831	-47%
onroad	5,708,150	1,786,856	-69%
ptfire	333,398	333,398	0%
ptegu	2,096,058	1,051,725	-50%
ptnonipm	1,212,616	1,156,792	-5%
pt_oilgas	509,856	424,595	-17%
rail	791,381	563,382	-29%
rwc	34,436	34,918	1%
Con U.S. Total	**14,163,853**	**7,939,069**	**-44%**
Offshore to EEZ	904,453	716,768	-21%
Non-US SECA C3	191,001	266,129	39%
Canada othafdust	0	0	0%
Canada othar	376,758	238,830	-37%
Canada othon	332,349	141,282	-57%
Canada othpt	231,609	221,980	-4%
Canada ptfire_mxca	14,048	14,048	0%
Mexico othar	183,383	212,147	16%
Mexico othon	363,342	376,485	4%
Mexico othpt	333,368	376,422	13%
Mexico ptfire_mxca	31,403	31,403	0%
Non-US Total	**2,961,713**	**2,595,494**	**-12%**

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Table 5-6. National by-sector $PM_{2.5}$ emissions (tons/yr) summaries and percent change

Sector	2011 $PM_{2.5}$	2023 $PM_{2.5}$	% change 2011 to 2023
afdust_adj	923,590	1,009,616	9%
ag	0	0	0%
agfire	101,379	101,379	0%
cmv_c1c2	9,294	5,155	-45%
cmv_c3	8,829	1,884	-79%
nonpt	404,258	427,719	6%
np_oilgas	16,333	21,786	33%
nonroad	154,657	78,858	-49%
onroad	188,925	79,527	-58%
ptfire	1,844,263	1,844,263	0%
ptegu	208,122	138,932	-33%
ptnonipm	320,816	320,641	0%
pt_oilgas	13,935	14,847	7%
rail	23,963	13,165	-45%
rwc	381,252	362,651	-5%
Con U.S. Total	**4,599,616**	**4,420,423**	**-4%**
Offshore to EEZ	24,692	9,125	-63%
Non-US SECA C3	14,930	9,371	-37%
Canada othafdust	242,374	270,071	11%
Canada othar	157,205	151,849	-3%
Canada othon	5,014	5,025	0%
Canada othpt	25,784	31,196	21%
Canada ptfire_mxca	73,401	73,401	0%
Mexico othar	42,623	46,311	9%
Mexico othon	3,254	4,586	41%
Mexico othpt	45,963	54,940	20%
Mexico ptfire_mxca	87,025	87,025	0%
Non-US Total	**722,265**	**742,899**	**3%**

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Table 5-7. National by-sector PM_{10} emissions (tons/yr) summaries and percent change

Sector	2011 PM_{10}	2023 PM_{10}	% change 2011 to 2023
afdust_adj	6,732,941	7,498,365	11%
ag	0	0	0%
agfire	152,837	152,837	0%
cmv_c1c2	9,712	5,387	-45%
cmv_c3	9,946	2,126	-79%
nonpt	491,825	509,892	4%
np_oilgas	17,784	24,780	39%
nonroad	162,417	84,153	-48%
onroad	326,900	232,752	-29%
ptfire	2,171,987	2,171,987	0%
ptegu	283,066	173,057	-39%
ptnonipm	477,328	473,720	-1%
pt_oilgas	14,585	15,508	6%
rail	25,898	14,236	-45%
rwc	381,476	362,897	-5%
Con U.S. Total	**11,258,702**	**11,721,698**	**4%**
Offshore to EEZ	26,401	9,630	-64%
Non-US SECA C3	16,228	10,232	-37%
Canada othafdust	1,192,039	1,353,416	14%
Canada othar	288,021	284,898	-1%
Canada othon	15,107	5,520	-63%
Canada othpt	51,137	57,514	12%
Canada ptfire_mxca	87,398	87,398	0%
Mexico othar	90,691	95,486	5%
Mexico othon	8,788	9,581	9%
Mexico othpt	59,325	71,542	21%
Mexico ptfire_mxca	104,125	104,125	0%
Non-US Total	**1,939,261**	**2,089,342**	**8%**

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Table 5-8. National by-sector SO_2 emissions (tons/yr) summaries and percent change

Sector	2011 SO_2	2023 SO_2	% change 2011 to 2023
afdust_adj	0	0	0%
ag	0	0	0%
agfire	17,755	17,755	0%
cmv_c1c2	6,217	1,987	-68%
cmv_c3	84,992	4,824	-94%
nonpt	276,332	96,043	-65%
np_oilgas	17,232	49,707	188%
nonroad	4,031	2,380	-41%
onroad	28,195	12,114	-57%
ptfire	165,773	165,773	0%
ptegu	4,670,713	1,335,974	-71%
ptnonipm	1,049,374	731,219	-30%
pt_oilgas	66,577	64,990	-2%
rail	7,936	340	-96%
rwc	8,954	7,908	-12%
Con U.S. Total	**6,404,080**	**2,491,013**	**-61%**
Offshore to EEZ	139,270	11,615	-92%
Non-US SECA C3	120,316	69,507	-42%
Canada othafdust	0	0	0%
Canada othar	33,464	22,783	-32%
Canada othon	1,270	549	-57%
Canada othpt	522,537	409,282	-22%
Canada ptfire_mxca	6,481	6,481	0%
Mexico othar	10,184	12,159	19%
Mexico othon	4,432	6,370	44%
Mexico othpt	471,847	361,230	-23%
Mexico ptfire_mxca	6,394	6,394	0%
Non-US Total	**1,316,195**	**906,371**	**-31%**

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Table 5-9. National by-sector VOC emissions (tons/yr) summaries and percent change

Sector	2011 VOC	2023 VOC	% change 2011 to 2023
afdust_adj	0	0	0%
ag	0	0	0%
agfire	80,540	80,540	0%
cmv_c1c2	7,696	5,241	-32%
cmv_c3	4,888	7,639	56%
nonpt	3,671,322	3,452,177	-6%
np_oilgas	2,482,590	2,966,396	19%
nonroad	2,024,419	1,177,147	-42%
onroad	2,713,181	987,796	-64%
ptfire	4,688,094	4,688,094	0%
ptegu	38,060	32,702	-14%
ptnonipm	800,815	782,504	-2%
pt_oilgas	164,098	177,353	8%
rail	40,851	21,384	-48%
rwc	442,541	415,748	-6%
Con U.S. Total	**17,159,096**	**14,794,722**	**-14%**
Offshore to EEZ	81,713	92,462	13%
Non-US SECA C3	6,878	11,821	72%
Canada othafdust	0	0	0%
Canada othar	776,733	800,300	3%
Canada othon	138,319	47,883	-65%
Canada othpt	166,284	186,100	12%
Canada ptfire_mxca	194,844	194,844	0%
Mexico othar	420,637	505,017	20%
Mexico othon	136,891	143,725	5%
Mexico othpt	57,090	80,922	42%
Mexico ptfire_mxca	172,196	172,196	0%
Non-US Total	**2,151,585**	**2,235,269**	**4%**

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Table 5-10. Canadian province emissions changes from 2011 to 2023 for othon sector

2023 othon emissions (tons)	2011	2023	% diff (2023-2011)	2011	2023	% diff (2023-2011)	2011	2023	% diff (2023-2011)
Province	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Newfoundland	38,454	18,791	-51.1%	6,054	2,611	-56.9%	2,439	818	-66.4%
Prince Edward Island	12,516	6,398	-48.9%	2,985	1,100	-63.1%	980	300	-69.4%
Nova Scotia	66,500	30,624	-53.9%	10,626	4,183	-60.6%	4,560	1,385	-69.6%
New Brunswick	62,881	30,018	-52.3%	12,978	4,945	-61.9%	4,956	1,576	-68.2%
Quebec	450,802	238,728	-47.0%	94,288	33,176	-64.8%	33,137	10,911	-67.1%
Ontario	583,811	387,770	-33.6%	133,818	49,835	-62.8%	58,001	19,480	-66.4%
Manitoba	147,307	72,096	-51.1%	28,630	15,482	-45.9%	16,257	5,558	-65.8%
Saskatchewan	160,734	88,473	-45.0%	39,296	26,347	-33.0%	16,126	6,618	-59.0%
Alberta	428,529	249,051	-41.9%	108,703	69,301	-36.2%	38,108	15,453	-59.5%
British Columbia	296,378	158,262	-46.6%	64,498	30,926	-52.1%	29,932	10,786	-64.0%
Yukon	5,977	1,993	-66.7%	1,969	1,004	-49.0%	585	161	-72.4%
N W Territories	5,301	2,015	-62.0%	1,215	632	-48.0%	454	142	-68.7%
Nunavut	0	0	0.0%	0	0	0.0%	0	0	0.0%
Canada Total	2,259,190	1,284,220	-43.2%	505,059	239,542	-52.6%	205,535	73,190	-64.4%

Table 5-11. Canadian province emissions changes from 2011 to 2023 for othar sector

2023 othar emissions (tons)	2011	2023	% diff (2023-2011)	2011	2023	% diff (2023-2011)	2011	2023	% diff (2023-2011)
Province	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Newfoundland	240,084	266,592	11.0%	44,914	31,834	-29.1%	66,538	73,243	10.1%
Prince Edward Island	25,798	26,965	4.5%	3,179	1,661	-47.8%	8,447	8,584	1.6%
Nova Scotia	116,388	104,911	-9.9%	46,345	20,535	-55.7%	37,795	34,034	-10.0%
New Brunswick	78,228	84,324	7.8%	12,980	8,326	-35.9%	28,181	30,887	9.6%
Quebec	970,074	995,472	2.6%	124,163	72,342	-41.7%	278,853	280,783	0.7%
Ontario	977,428	1,043,706	6.8%	138,510	95,720	-30.9%	326,896	333,517	2.0%
Manitoba	100,965	121,472	20.3%	35,123	19,465	-44.6%	63,740	69,277	8.7%
Saskatchewan	120,537	133,515	10.8%	73,713	40,146	-45.5%	97,252	98,004	0.8%
Alberta	312,576	377,812	20.9%	150,466	106,892	-29.0%	219,727	241,602	10.0%
British Columbia	282,114	314,793	11.6%	133,298	77,738	-41.7%	104,627	113,422	8.4%
Yukon	7,418	7,822	5.4%	419	6,441	1435.6%	2,439	2,566	5.2%
N W Territories	4,094	3,239	-20.9%	2,536	1,864	-26.5%	1,536	1,187	-22.7%
Nunavut	30,279	41,032	35.5%	3,228	12,542	288.5%	7,776	11,101	42.8%
Canada Total	3,265,982	3,521,654	7.8%	768,873	495,504	-35.6%	1,243,806	1,298,207	4.4%

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Table 5-12. Canadian province emissions changes from 2011 to 2023 for othpt sector

2023 othpt emissions (tons)	**2011**	**2023**	**% diff (2023-2011)**	**2011**	**2023**	**% diff (2023-2011)**	**2011**	**2023**	**% diff (2023-2011)**
Province	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Newfoundland	9,951	11,245	13.0%	15,449	17,288	11.9%	4,707	4,984	5.9%
Prince Edward Island	167	153	-8.4%	269	234	-13.0%	210	236	12.7%
Nova Scotia	16,033	3,616	-77.4%	23,948	17,174	-28.3%	5,853	4,841	-17.3%
New Brunswick	20,861	24,210	16.1%	15,790	17,138	8.5%	6,465	7,275	12.5%
Quebec	470,224	641,119	36.3%	39,911	42,254	5.9%	37,770	39,339	4.2%
Ontario	92,784	103,009	11.0%	76,441	77,106	0.9%	64,127	64,552	0.7%
Manitoba	4,777	5,583	16.9%	3,590	4,250	18.4%	23,880	20,134	-15.7%
Saskatchewan	47,251	47,839	1.2%	69,971	57,526	-17.8%	188,075	223,364	18.8%
Alberta	556,850	574,346	3.1%	489,584	421,837	-13.8%	556,009	554,800	-0.2%
British Columbia	181,571	280,949	54.7%	86,375	140,438	62.6%	74,301	104,369	40.5%
Yukon	288	216	-25.1%	18	27	50.7%	24	32	33.2%
N W Territories	4,217	4,847	14.9%	9,497	15,040	58.4%	2,036	2,155	5.9%
Nunavut	843	686	-18.6%	3,154	1,110	-64.8%	49	37	-23.3%
Canada Total	1,405,817	1,697,818	20.8%	833,998	811,424	-2.7%	963,504	1,026,119	6.5%

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Table 5-13. Mexican state emissions changes from 2011 to 2023 for othon sector

2023 othon emissions (tons)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)
State	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Aguascalientes	74,458	72,499	-2.6%	18,716	19,700	5.3%	7,126	7,314	2.6%
Baja Calif Norte	292,747	316,731	8.2%	74,570	77,577	4.0%	25,233	26,025	3.1%
Baja Calif Sur	83,274	91,452	9.8%	19,961	20,750	4.0%	6,999	7,340	4.9%
Campeche	52,849	58,506	10.7%	9,367	9,834	5.0%	3,948	4,122	4.4%
Coahuila	170,357	165,632	-2.8%	38,217	40,294	5.4%	15,532	16,135	3.9%
Colima	59,533	65,737	10.4%	11,485	12,026	4.7%	4,735	5,004	5.7%
Chiapas	114,015	125,700	10.2%	23,295	24,325	4.4%	9,109	9,519	4.5%
Chihuahua	280,049	271,634	-3.0%	76,676	80,295	4.7%	26,460	27,193	2.8%
Distrito Federal	602,306	602,050	0.0%	143,350	138,120	-3.6%	60,134	60,474	0.6%
Durango	98,318	107,195	9.0%	24,238	25,168	3.8%	8,817	9,370	6.3%
Guanajuato	230,777	224,860	-2.6%	57,800	60,848	5.3%	22,563	23,431	3.8%
Guerrero	156,199	172,474	10.4%	28,815	30,232	4.9%	12,770	13,669	7.0%
Hidalgo	131,136	127,736	-2.6%	34,009	35,730	5.1%	12,794	13,110	2.5%
Jalisco	456,462	433,740	-5.0%	122,360	125,191	2.3%	45,893	47,241	2.9%
Mexico	413,998	448,551	8.3%	102,556	103,470	0.9%	38,111	38,793	1.8%
Michoacan	301,589	330,111	9.5%	68,641	71,574	4.3%	27,435	29,395	7.1%
Morelos	83,388	81,392	-2.4%	19,926	20,997	5.4%	7,929	8,274	4.3%
Nayarit	71,260	78,690	10.4%	13,702	14,352	4.7%	5,947	6,409	7.8%
Nuevo Leon	340,264	353,709	4.0%	86,518	86,734	0.3%	34,033	35,793	5.2%
Oaxaca	98,480	95,690	-2.8%	26,792	27,781	3.7%	8,496	8,625	1.5%
Puebla	196,606	212,743	8.2%	49,244	51,425	4.4%	18,745	19,950	6.4%
Queretaro	71,514	69,650	-2.6%	20,361	21,327	4.7%	6,963	7,164	2.9%
Quintana Roo	67,166	65,537	-2.4%	13,672	14,466	5.8%	5,594	5,739	2.6%
San Luis Potosi	144,504	140,708	-2.6%	32,362	34,138	5.5%	13,518	14,187	4.9%
Sinaloa	203,180	223,769	10.1%	46,984	48,875	4.0%	17,555	18,869	7.5%
Sonora	195,052	214,002	9.7%	46,289	48,130	4.0%	17,094	18,303	7.1%
Tabasco	93,227	103,029	10.5%	17,304	18,148	4.9%	7,343	7,754	5.6%
Tamaulipas	296,180	325,932	10.0%	58,506	61,170	4.6%	24,360	25,872	6.2%
Tlaxcala	33,247	32,217	-3.1%	8,901	9,355	5.1%	3,266	3,321	1.7%
Veracruz	265,631	259,302	-2.4%	68,186	71,617	5.0%	24,046	24,651	2.5%
Yucatan	97,722	95,382	-2.4%	20,606	21,783	5.7%	8,431	8,745	3.7%
Zacatecas	112,450	122,582	9.0%	28,420	29,527	3.9%	10,411	11,130	6.9%
Mexico Total	5,887,937	6,088,942	3.4%	1,411,830	1,454,958	3.1%	541,390	562,919	4.0%

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Table 5-14. Mexican state emissions changes from 2011 to 2023 for othar sector

2023 othar emissions (tons)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)
State	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Aguascalientes	4,018	4,901	22.0%	6,605	7,492	13.4%	19,358	23,699	22.4%
Baja Calif Norte	13,589	19,079	40.4%	21,841	28,254	29.4%	61,514	77,009	25.2%
Baja Calif Sur	3,110	4,372	40.6%	4,996	6,085	21.8%	10,889	14,748	35.4%
Campeche	51,137	55,561	8.7%	35,074	34,844	-0.7%	35,129	41,592	18.4%
Coahuila	12,444	14,769	18.7%	15,089	19,367	28.4%	48,687	58,739	20.6%
Colima	8,562	10,303	20.3%	3,883	4,601	18.5%	16,571	20,176	21.8%
Chiapas	305,524	354,916	16.2%	22,097	23,492	6.3%	312,206	365,483	17.1%
Chihuahua	61,301	67,860	10.7%	55,606	59,045	6.2%	99,006	116,057	17.2%
Distrito Federal	10,780	14,230	32.0%	7,966	10,765	35.1%	108,040	112,654	4.3%
Durango	39,499	43,328	9.7%	27,428	28,670	4.5%	51,830	59,027	13.9%
Guanajuato	71,662	83,363	16.3%	41,641	49,568	19.0%	122,993	141,500	15.0%
Guerrero	156,577	167,856	7.2%	5,770	6,172	7.0%	176,647	192,150	8.8%
Hidalgo	98,080	110,966	13.1%	17,781	21,582	21.4%	113,582	128,929	13.5%
Jalisco	61,762	70,602	14.3%	47,329	50,076	5.8%	147,659	174,141	17.9%
Mexico	178,322	219,642	23.2%	32,009	37,849	18.2%	344,893	416,931	20.9%
Michoacan	115,037	132,429	15.1%	21,496	37,382	73.9%	152,964	171,488	12.1%
Morelos	26,857	27,190	1.2%	13,692	5,457	-60.1%	45,963	52,672	14.6%
Nayarit	23,142	26,534	14.7%	13,483	13,091	-2.9%	30,199	36,612	21.2%
Nuevo Leon	31,440	38,770	23.3%	24,518	30,517	24.5%	88,474	108,061	22.1%
Oaxaca	238,829	255,390	6.9%	13,735	14,059	2.4%	250,320	270,763	8.2%
Puebla	202,340	227,306	12.3%	17,744	21,075	18.8%	250,507	283,412	13.1%
Queretaro	26,941	34,278	27.2%	8,463	12,791	51.1%	50,165	61,365	22.3%
Quintana Roo	26,335	35,351	34.2%	5,137	5,773	12.4%	38,633	53,296	38.0%
San Luis Potosi	88,201	98,880	12.1%	22,207	27,521	23.9%	106,283	118,702	11.7%
Sinaloa	54,362	59,869	10.1%	35,373	38,123	7.8%	76,165	85,204	11.9%
Sonora	26,007	30,706	18.1%	23,917	27,984	17.0%	60,018	72,372	20.6%
Tabasco	91,388	102,556	12.2%	14,024	16,009	14.1%	103,490	117,803	13.8%
Tamaulipas	44,743	51,876	15.9%	46,959	54,576	16.2%	70,902	83,656	18.0%
Tlaxcala	21,451	25,104	17.0%	6,672	7,438	11.5%	32,549	38,656	18.8%
Veracruz	357,503	389,550	9.0%	48,159	50,987	5.9%	390,957	432,607	10.7%
Yucatan	97,808	113,125	15.7%	7,176	7,935	10.6%	111,556	131,043	17.5%
Zacatecas	30,865	32,736	6.1%	38,745	40,253	3.9%	36,798	40,838	11.0%
Mexico Total	2,579,614	2,923,397	13.3%	706,612	798,834	13.1%	3,564,949	4,101,385	15.0%

Table 5-15. Mexican state emissions changes from 2011 to 2023 for othpt sector

2023 othpt emissions (tons)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)	2011el	2023el	% diff (2023el-2011el)
State	CO	CO	CO	NOX	NOX	NOX	VOC	VOC	VOC
Aguascalientes	275	391	42.3%	987	1,407	42.6%	2,151	3,069	42.7%
Baja Calif Norte	8,083	17,500	116.5%	14,498	32,455	123.9%	13,603	19,505	43.4%
Baja Calif Sur	644	173	-73.1%	8,899	2,582	-71.0%	610	771	26.4%
Campeche	9,342	11,361	21.6%	35,616	41,077	15.3%	3,637	4,324	18.9%
Coahuila	31,659	35,549	12.3%	217,689	218,533	0.4%	7,328	10,306	40.6%
Colima	1,496	1,052	-29.7%	15,921	7,294	-54.2%	1,514	2,152	42.1%
Chiapas	2,861	3,919	37.0%	5,503	7,500	36.3%	3,926	5,439	38.5%
Chihuahua	11,318	15,659	38.4%	11,989	13,663	14.0%	5,540	7,803	40.8%
Distrito Federal	887	1,321	49.0%	2,582	3,853	49.2%	25,747	36,748	42.7%
Durango	3,552	4,737	33.4%	6,988	7,371	5.5%	3,727	5,261	41.1%
Guanajuato	78,844	95,712	21.4%	9,566	12,567	31.4%	11,245	14,846	32.0%
Guerrero	3,200	3,184	-0.5%	14,706	14,270	-3.0%	785	952	21.2%
Hidalgo	123,941	218,498	76.3%	35,641	50,270	41.0%	8,325	14,004	68.2%
Jalisco	3,766	5,367	42.5%	7,403	10,547	42.5%	18,313	26,129	42.7%
Mexico	7,294	14,501	98.8%	17,656	35,567	101.4%	56,433	81,136	43.8%
Michoacan	3,341	4,753	42.3%	4,966	6,938	39.7%	6,306	8,997	42.7%
Morelos	1,553	2,216	42.7%	4,249	6,064	42.7%	3,381	4,825	42.7%
Nayarit	553	789	42.8%	375	538	43.2%	1,673	2,387	42.7%
Nuevo Leon	86,971	107,975	24.1%	41,887	57,573	37.4%	15,730	22,180	41.0%
Oaxaca	113,001	135,442	19.9%	10,928	13,944	27.6%	8,267	10,729	29.8%
Puebla	2,994	4,748	58.6%	7,360	11,104	50.9%	4,317	6,168	42.9%
Queretaro	3,184	6,613	107.7%	9,793	22,762	132.4%	7,013	10,332	47.3%
Quintana Roo	410	550	34.1%	616	388	-37.0%	1,016	1,441	41.8%
San Luis Potosi	6,764	14,529	114.8%	22,263	33,743	51.6%	7,563	11,590	53.2%
Sinaloa	1,315	1,098	-16.5%	10,982	2,049	-81.3%	3,641	5,076	39.4%
Sonora	4,299	8,350	94.2%	14,581	18,526	27.1%	4,786	7,018	46.6%
Tabasco	7,682	10,102	31.5%	23,255	29,986	28.9%	6,767	8,468	25.1%
Tamaulipas	71,893	89,752	24.8%	34,020	42,968	26.3%	34,256	46,543	35.9%
Tlaxcala	286	435	52.1%	962	1,531	59.1%	1,425	2,033	42.7%
Veracruz	88,864	108,452	22.0%	48,607	56,892	17.0%	30,199	40,973	35.7%
Yucatan	3,210	3,679	14.6%	11,020	11,529	4.6%	4,454	6,206	39.3%
Zacatecas	3	4	42.0%	11	15	42.4%	226	322	42.7%
Mexico Total	683,482	928,414	35.8%	651,521	775,506	19.0%	303,905	427,730	40.7%

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From: Joseph Jakuta
Location: https://global.gotomeeting.com/join/ Ex. 6
Importance: Normal
Subject: OTC Modeling Committee
Start Date/Time: Tue 9/19/2017 5:00:00 PM
End Date/Time: Tue 9/19/2017 6:30:00 PM
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Draft Agenda:

1. Meetings

a. Committee Meeting Update
b. ADs Meeting

2. 2011 Modeling Platform Update

c. Inventory Status

i. ERTAC
ii. 2020 MARAMA Work
iii. 2023 EPA 'en'
iv. 2028 EPA 'el'

d. CMAQ Modeling (2011/2020)

v. Preliminary 2011 Gamma Results
vi. Other Planning

e. CAMx Modeling (2011/2023/2017)

3. BenMap
4. Conceptual Model Workgroup

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Access Code: Ex. 6
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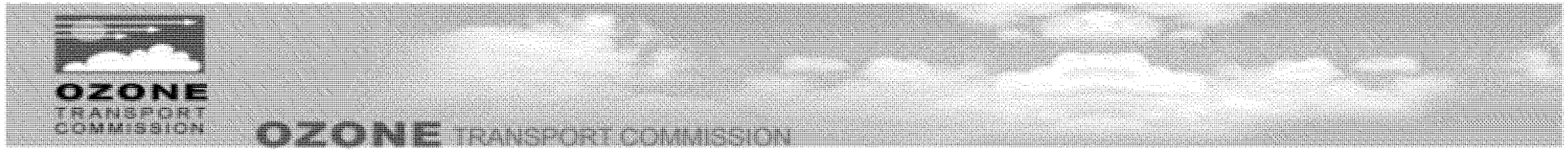
Modeling Committee Update

OTC Air Directors Meeting

October 10, 2017

Linthicum, MD



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Overview

1. Ozone Monitoring Update
2. Ozone NAAQS Schedule
3. BenMap
4. OTC 2011 Modeling Platform
   a) Inventory Status/Updates
   b) Screening Modeling Status
5. New Modeling Platform Update
6. Enhanced Monitoring Plan (EMP)
7. Conceptual Model

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