UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

Reply To
Attn Of: OAQ-107

SEP 1 1998

Mr. Allen W. Conklin, Manager
Air Emissions and Defense Waste Section
Division of Radiation Protection
Washington State Department of Health
P.O. Box 47827
Olympia, Washington 98504-7827

Re: Air Inspection at U.S. Department of Energy, Hanford Site

Dear Mr. Conklin:

On May 11, 1998, Emad Shahin of the Environmental Protection Agency (EPA) accompanied a team of inspectors from the State of Washington Departments of Health (DOH) and Ecology on a multi-media compliance inspection of the Department of Energy's Hanford facilities. Enclosed is one copy each of Mr. Shahin's inspection report (minus the attachments) and the compliance analysis.

DOH cited violations of the National Emission Standards for Hazardous Air Pollutants (40 CFR § 61.93(b)(2)(ii)) for failure to continuously monitor or obtain approval of periodic confirmatory monitoring to verify low emissions, and for failure to comply with the State's Notice of Construction requirements. A Notice of Violation (including a Notice of Correction / Compliance Order) was issued on May 13, 1998, which addressed these violations and ordered the Department of Energy to comply with the applicable requirements. Please forward documents submitted to you in response to your order that show resolution of the above violations.

For technical questions please call Emad Shahin at (206) 553-1423, or you can call me at (206) 553-8257.

Sincerely,

Don Dossett

Don Dossett
Compliance Team Leader
Office of Air Quality

DD:cb
Enclosure

c: Cindy Grant, DOH, Seattle (w/enclosure)
Jerry Hensley, Ecology, Kennewick (w/enclosure)
Jerry Leitch, EPA, OAQ

h\apb\transltr.wa3

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File:
✓ Enf/compliance
TV Application
TV Activity
Other

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

July 9, 1998

Reply to
Attn. of: OEA-095

MEMORANDUM

SUBJECT: Air Inspection Report
Multi-Media Inspection
U.S. Department of Energy, Hanford Site
Richland, washington

FROM: Emad S. Shahin
Environmental Engineer, IEU, OEA

TO: Don Dossett, P.E.
Air Compliance Team Leader, OAQ

Attached is the air compliance inspection report for the US DOE, Hanford site at Richland, Washington. This inspection was performed as a part of a Multi-Media inspection conducted on May 11, 1998. Washington Department of Health inspectors conducted a comprehensive and detailed inspection that in my opinion exceeded the requirements for a level 2 inspection. They wrote a detailed report accordingly. I included that report as attachment 2. A compliance analysis is also attached.

If you have any questions, feel free to call me at 3-1423.

Attachment

cc: Gil Haselberger, OAQ
Phil Wong, OEA

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JUL 30 1998
PCCEMS/AIRS

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

July9, 1998

Reply to
Attn. of: OEA-095

MEMORANDUM

SUBJECT: Compliance Analysis for the US department of Energy, Hanford Site in Richland, Washington

FROM: Emad S. Shahin
Environmental Engineer, IEU, OEA

TO: Don Dossett, P.E.
Air Compliance Team Leader, OAQ

Attached is the compliance analysis for the US DOE, Hanford Site in Richland, Washington. With regard to my opinion of the adequacy of the Washington Department of Health (WDOH) inspection, I thought that the WDOH inspectors John Schmidt, John Martell, Gail Laws, and Johanna Berkey had a thorough knowledge of the facility processes, control equipment, and applicable regulations. They conducted a detailed and comprehensive inspection that met the Level 2 inspection criteria.

If you wish to discuss my findings, feel free to call me at extension 1423.

Attachment

cc: Gil Haselberger, OAQ
Phil Wong, OEA

Printed on Recycled Paper

Compliance Analysis
US DOE, Hanford Site
Emad Shahin, OEA
July 9, 1998

This analysis summarizes my evaluation of compliance for the US Department of Energy, Hanford Site in Richland, Washington with the EPA regulations under the Clean Air Act. The regulations reviewed in the compliance analysis include PSD, NSPS, NESHAPS, and the federally approved SIP.

Items Reviewed

This evaluation was based on the inspection report for the facility dated July 9, 1998, and a review of the OAQ and WDOH files for the facility.

Prevention of Significant Deterioration (PSD)

In March 1997, US DOE submitted an application to Washington Department of Ecology requesting authorization to install approximately forty one new boilers with maximum heat input capacity ranging from 0.4 to 26.3 MM Btu per hour. Since the Hanford Site is a major source, a PSD review would be required for any changes that would result in a net increase in a criteria pollutant emissions above the threshold levels. Only the potential annual emissions for NOx and CO exceed their respective PSD Significance Levels, but these emissions were sufficiently offset by the emission reductions associated with decommissioning the older boilers at the site. A PSD permit was not required.

New Source Performance Standards (NSPS)

Subpart Dc applies to the boilers with heat input capacity of 10 MM Btu/hr or more, but less than 100 MM Btu/hr. Initial compliance testing was performed on the boilers burning fuel oil on 11/13/97, and on 12/12/97. These tests were observed by WDOE staff. Emissions from the tests appeared to be much less than the specified limits of Subpart Dc. The larger boilers with firing rates equal to or greater than 5 MM Btu/hr are equipped with low NOx burners with FGR. A list of the boilers that were tested and the results are attached as attachment No.7.

National Emission Standards for Hazardous Air Pollutants (NESHAPS)

This facility is subject to the NESHAP Regulations, Subpart H for emissions of radionuclides other than radon from Department of Energy facilities. During the running of the plasma arc furnace in the Waste Technology Engineering Laboratory, Building 324, the tritium samplers were turned off, violating the requirement 40CFR 61.93(b)(2)(ii) for confirmatory sampling to verify low emissions of tritium. WDOH issued a Notice of violation dated May 13, 1998.(refer to attachment 5)

State Implementation Plan (SIP)

The Hanford site is subject to WDOE and WDOH regulations. A notice of construction for the plasma arc furnace was issued in July of 1996, and a modification was approved in August 1997. The NOC specified that the furnace is to treat "Buried Waste" from across the DOE Complex. In April of 1998, the DOE processed obsolete nuclear weapons components containing tritium, which are not considered buried waste. DOE failed to obtain approval from WDOH and failed to disclose the nature and general description of the material processed. WDOH issued a Notice of Violation, with a compliance order on May 13, 1998. (Attachment 5)

Summary of Violations and Recommended Actions

The Compliance Order conditions are in attachment 5. The US DOE responded with a letter dated July 7, 1998 requesting an extension on the time period required to demonstrate compliance with item # 3 of the compliance Order. On the other hand, DOE appeared to be able to satisfy conditions #1 and 2. (Attachment 6). At this time, I do not have recommendations of any actions against the facility, since WDOH is handling these issues.

Air Compliance Inspection Report

Facility:	U.S. Department of Energy, Hanford Site Richland, Washington
Facility Representatives:	Hector Rodreguez, DOE/RL, (509) 376-6421 Russell Johnson, Contractor, Waste Management, Inc.
Agency Inspectors:	Emad Shahin, Environmental Engineer, EPA (report author) John Schmidt, John Martel, Gail Laws, and Johanna Berky, Washington Department of Health Jerry Hensley, Environmental Engineer, Washington Department of Ecology
Date of Inspection:	May 11, 1998
Date of Report:	July 9, 1998

Background

The Hanford site occupies an area of approximately 560 square miles located north of Richland and the confluence of the Yakima River with the Columbia River. The site was established in 1943 to produce plutonium for some of the nuclear weapons tested and used in World War II.. Hanford operations have resulted in the production of liquid, solid, and gaseous wastes. Most of these wastes contained or had the potential to contain radioactive materials. The mission of the Hanford site is no longer plutonium production. The site emphasizes cleanup and restoration, waste management, research and development of new waste treatment and disposal technologies. (See attachment 1 for site maps and layout)

File Review

Prior to the inspection I reviewed the EPA air compliance file for the Hanford site. According to the files, there were no multi media inspections conducted at the site. The file indicated that Hanford site applied for a Title V operating permit with the Department of Ecology. A copy of the draft permit was sent to EPA for review during the public comments period. The public comments period ended last month. Once Ecology prepares a proposed permit to the EPA with the changes that were made during the public comments period, EPA will have 45 days to review the proposed permit. The permit application addresses air emissions from more than 380 individual emission points. The Washington Department of Health regulates airborn radionuclide emissions and has permitted the emissions under permit number FF . The file also includes a Notice of Construction for 44 new boilers in the 200 East, 200 West, and 300 areas. The boilers vary in size, with heat input capacity range between 0.4 MMBtu/hr to 26.3MMBtu/hr. The boilers are equipped with low NOx burners and flue gas recirculation

(FGR) which has been determined to be best available control technology for NOx.. The files also contain a notice of violation issued by WaDOH on May 13, 1998 for violating the radioactive air emissions regulations in the operation of the plasma arc furnace in the 324 building - Waste Technology Engineering Laboratoy, located in the 300 area.
I attended several meetings prior to the inspection, with Washington Department of Health (WaDOH), and Department of Ecology (WaDOE) to plan and coordinate for the inspection by talking to our counterparts and outlining the areas of concern and the issues that needed to be discussed during the inspection.

Opening Conference

We arrived at the Federal Building in Richland on Monday May 11, 1998 at 1:00 PM for the opening conference. Doug Smith started the conference by stating our purpose and goal of the multimedia inspection. He explained how facilities are chosen for such inspections and explained what each media might be interested in looking at. Then Doug asked each media lead to discuss his/her interests and elaborate on what they would be looking for. I stated that I will be conducting the radionuclide emissions inspection jointly with the WaDOH inspectors, and for the non-radionuclide inspection, I would be looking at how the facility demonstrates compliance with the applicable regulations. After the conference I went to get a DOE visitor badge, and went through the required safety training. The physical inspection of the facility started on Tuesday May, 12, 1998.

Inspection

- Radionuclides Inspection : Please refer to attachment 2 (WADOH Inspection Report)

-Non-Radionuclides Inspection

I asked Mr. Rodreguez and Mr. Johnson about boilers at the site They stated that several large coal and oil fired boilers that serviced the 200 and 300 areas were replaced by 41 new boilers firing either natural gas or low sulfur distillate oil and a Notice of Construction application for this project was submitted to the WDOE and has been approved. (Attachment 3). DOE has contracted with Johnson Controls, Inc. to maintain the boilers. Operations of the boilers are monitored and controlled from a central control facility located in the three hundred area. On Wednesday after noon, May 13, 1998, I stopped at the 300 area boilers control room. The boilers are equipped with low NOx burners and flue gas recirculation (FGR) which has been determined to be best available control technology for NOx. NSPS Subpart Dc is applicable to the five oil fired boilers that are greater than 10 MM Btu/hr. Initial performance tests have been conducted and reports of the results were submitted to the WDOE. Attachment 4 includes the fuel supplier certificate of the oil sulfur content, and the monthly emission calculations for the boilers.

Closing Conference

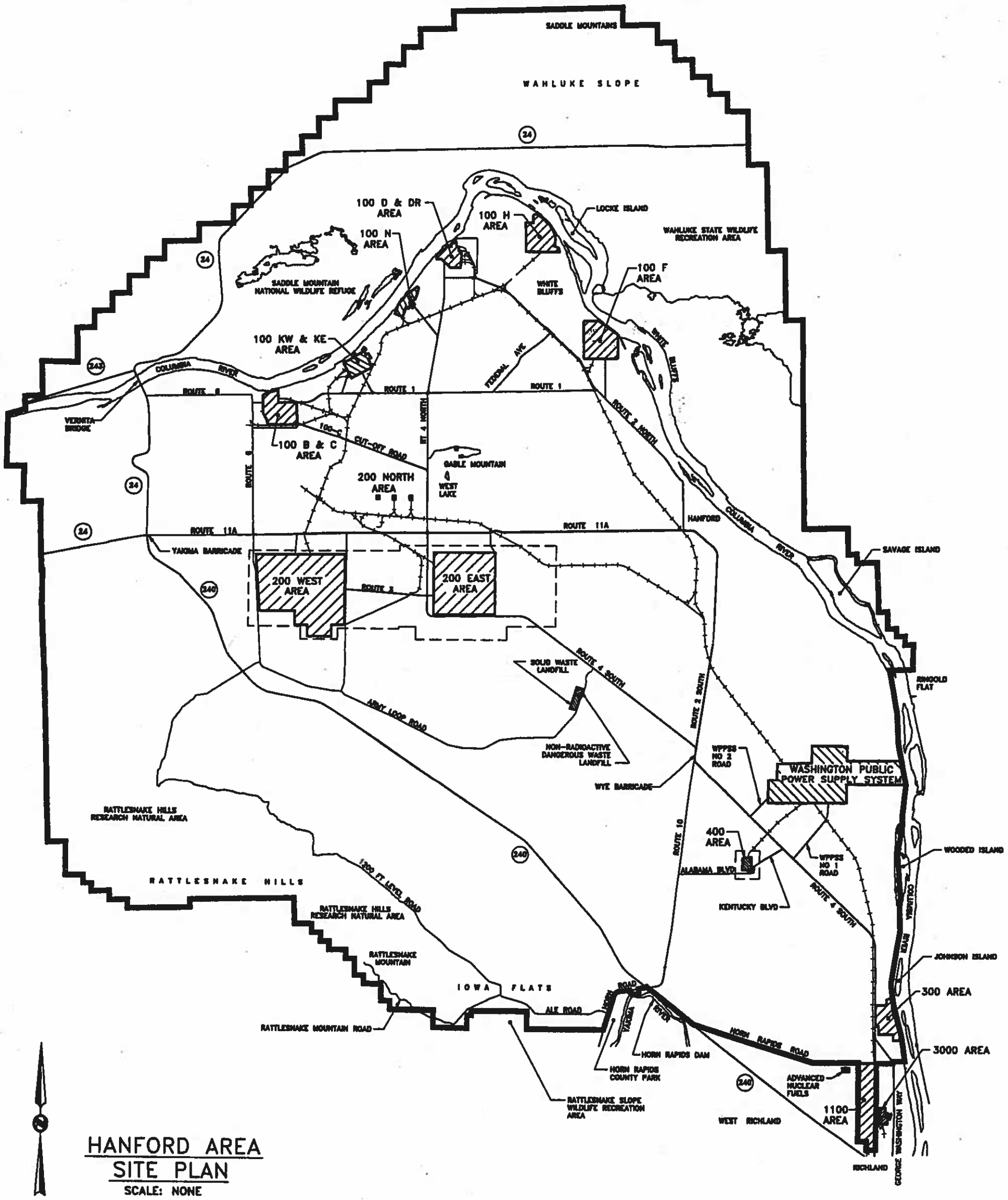
I completed my inspection according to the WDOH inspection schedule on Friday, May 15, 1998. I returned to the Federal Building in Richland with Doug Smith for a debriefing on the

first week of the inspection. At 1:00 PM we debriefed Mr. John Wagoner, the Hanford Site Manager and discussed some areas of concern. The WDOH inspectors were also present. We left the Federal building at approximately at 3:00 PM.

List of Attachments

Attachment No.	Description
1	Site map and plot plan
2	WDOH Inspection Report
3	Boilers Replacement NOC
4	Boiler Emissions and Fuel Certificate
5	A Copy of the NOV issued by WDOH
6	A Copy of the Response Letter by US DOE
7	Results of the Initial Performance Tests for the Boilers

attachment 1



HANFORD AREA SITE PLAN

SCALE: NONE

PRODUCED BY: SYSTEM DESIGN SERVICES
FOR ADDITIONAL MAPS CALL 373-2792

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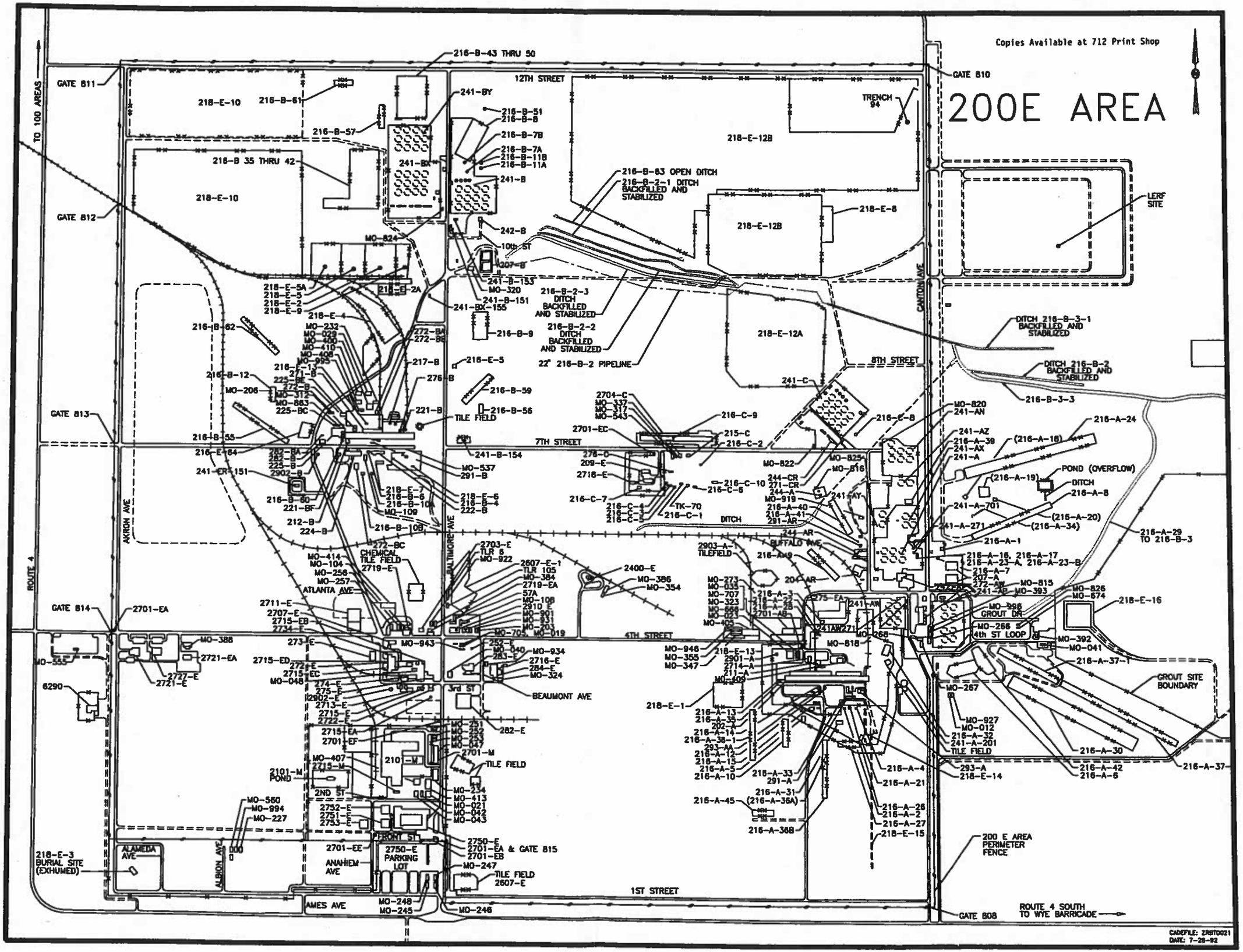
DATE: 7-29-92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200E AREA
TO 100 AREAS
GATE 811
GATE 812
GATE 813
GATE 814
GATE 810
GATE 808
12TH STREET
8TH STREET
7TH STREET
4TH STREET
3rd ST
2ND ST
FRONT ST
1ST STREET
AKRON AVE
ROUTE 4
ATLANTA AVE
BALTIMORE AVE
BEAUMONT AVE
CANTON AVE
BUFFALO AVE
ALAMEDA AVE
ALBION AVE
ANAHEIM AVE
AMES AVE
TRENCH 94
LERF SITE
GROUT SITE BOUNDARY
200 E AREA PERIMETER FENCE
ROUTE 4 SOUTH TO WYE BARRICADE
POND (OVERFLOW)
TILE FIELD
CHEMICAL TILE FIELD
2750-E PARKING LOT
218-E-3 BURIAL SITE (EXHUMED)
CADFILE: 2RST0021
DATE: 7-28-92

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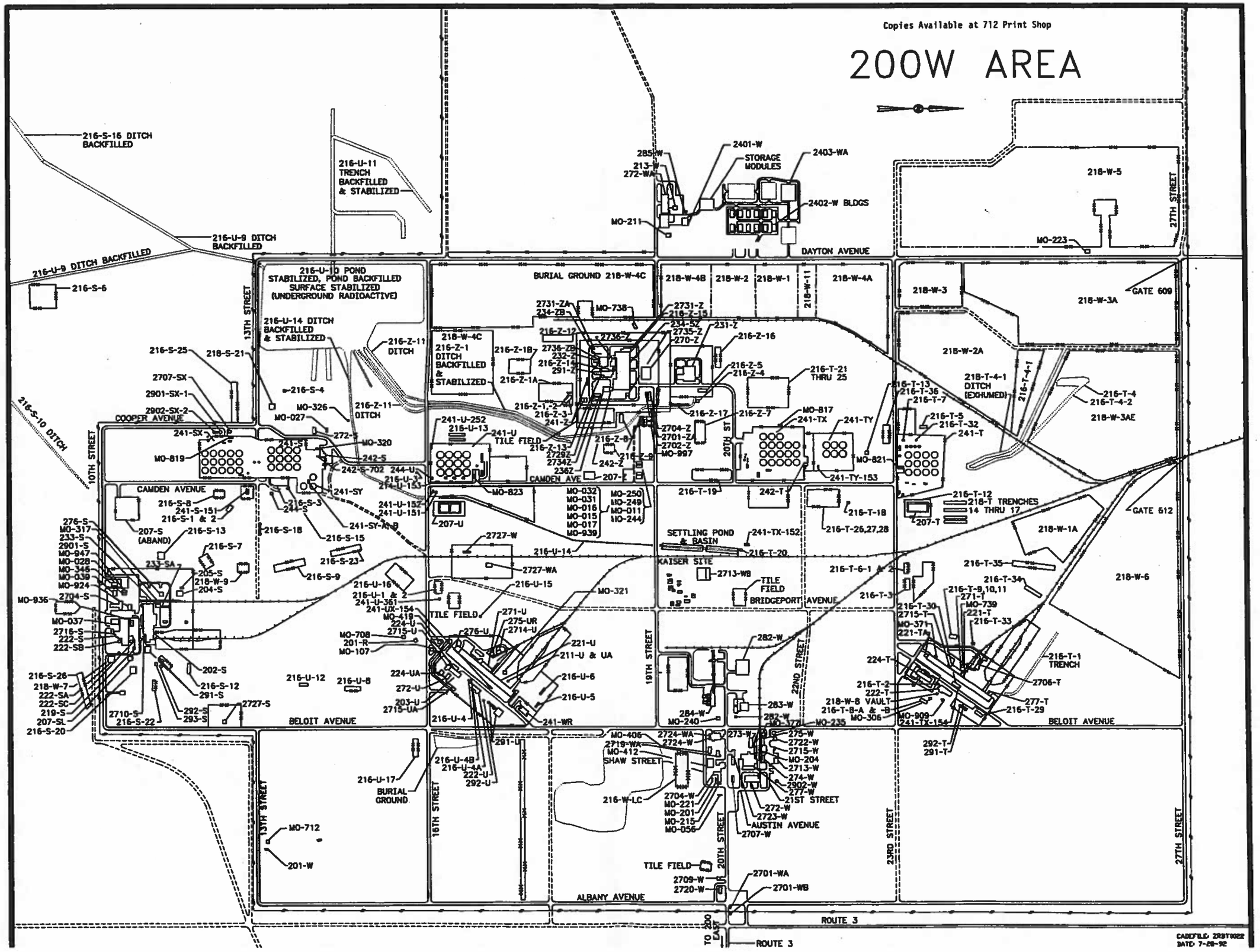
200W AREA



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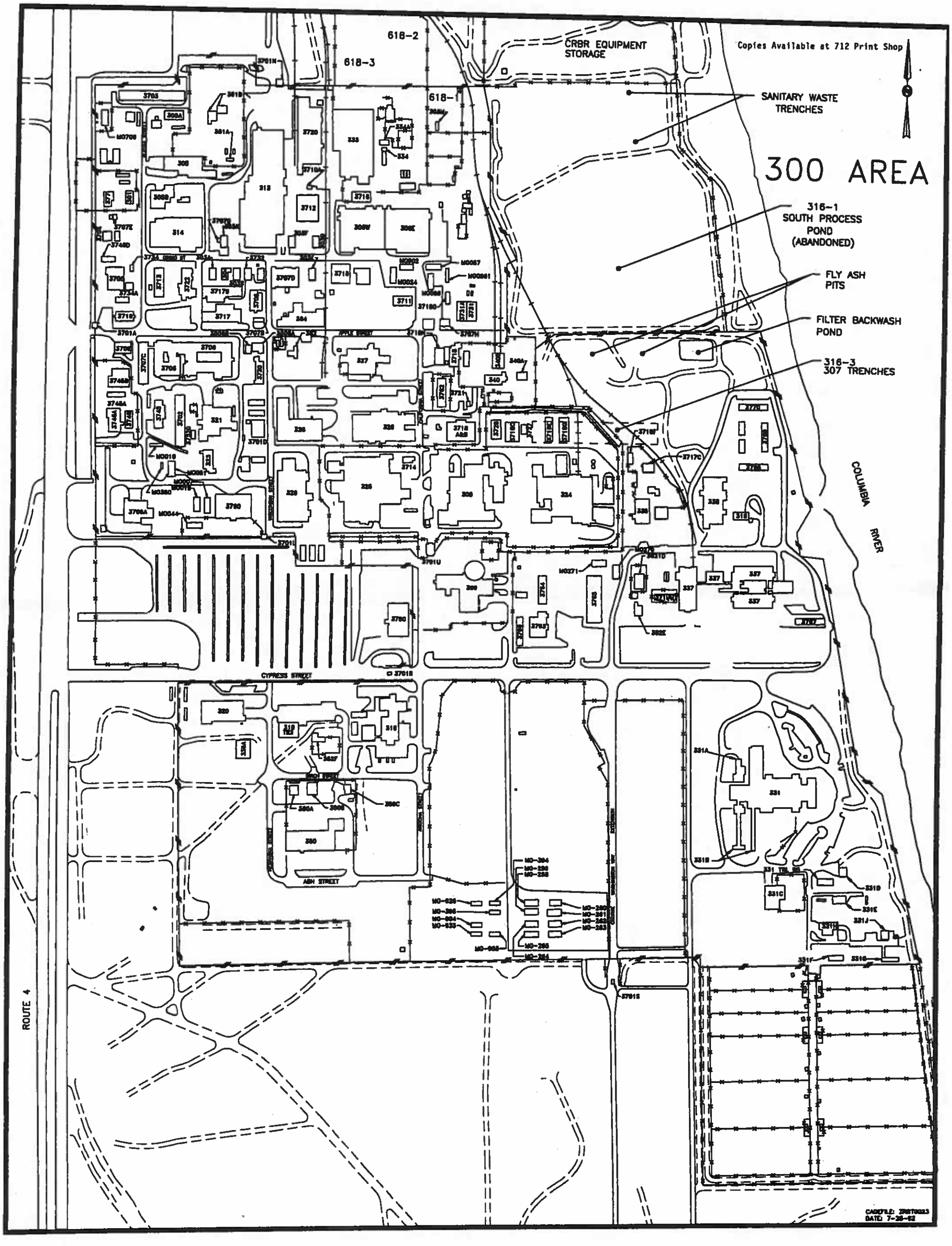
DATE: 7-28-92


Copies Available at 712 Print Shop
300 AREA
CRBR EQUIPMENT STORAGE
SANITARY WASTE TRENCHES
316-1 SOUTH PROCESS POND (ABANDONED)
FLY ASH PITS
FILTER BACKWASH POND
316-3 307 TRENCHES
618-2
618-3
618-1
COLUMBIA RIVER
ROUTE 4
CYPRESS STREET
ASH STREET

400AREA

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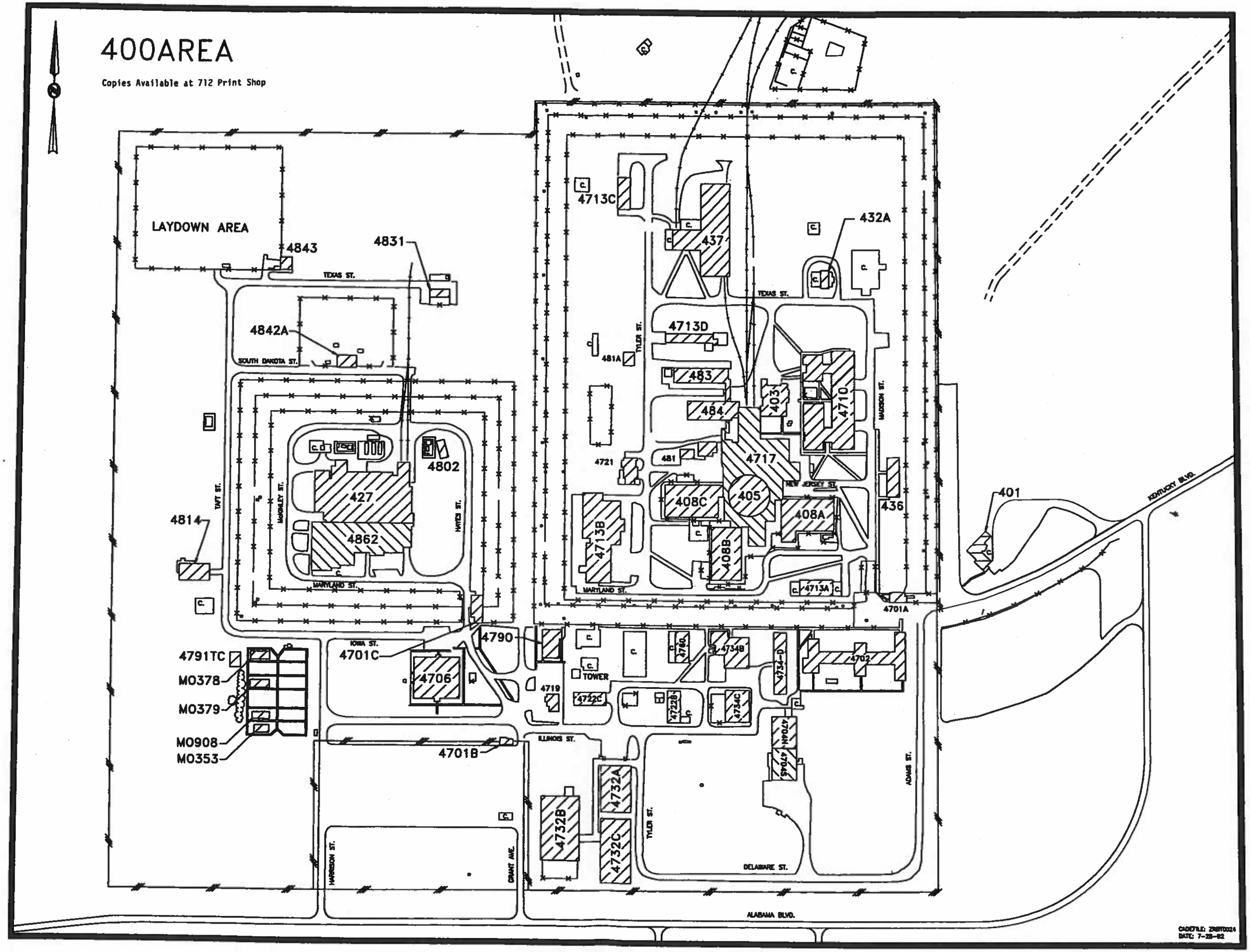

100B AREA

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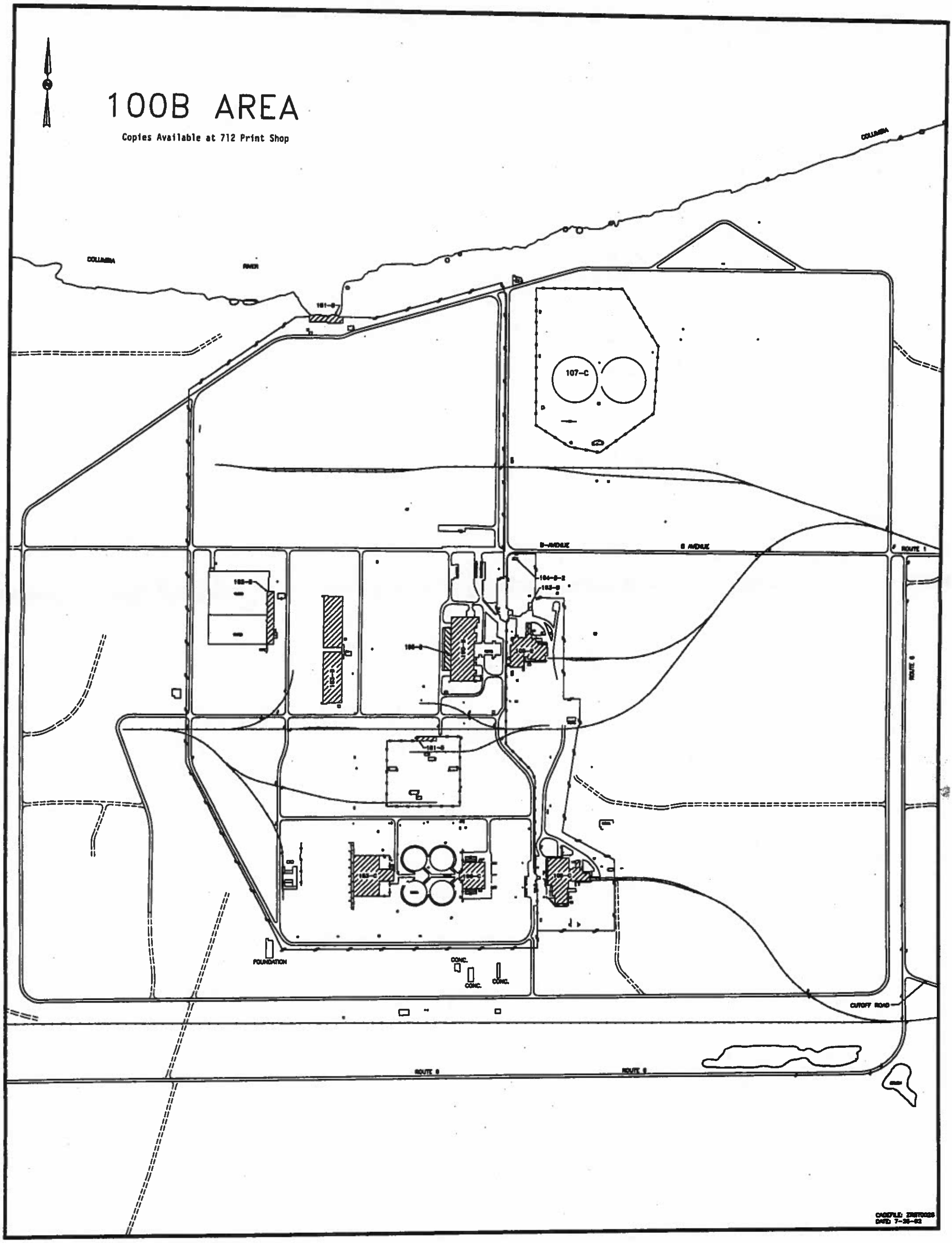

100K AREA

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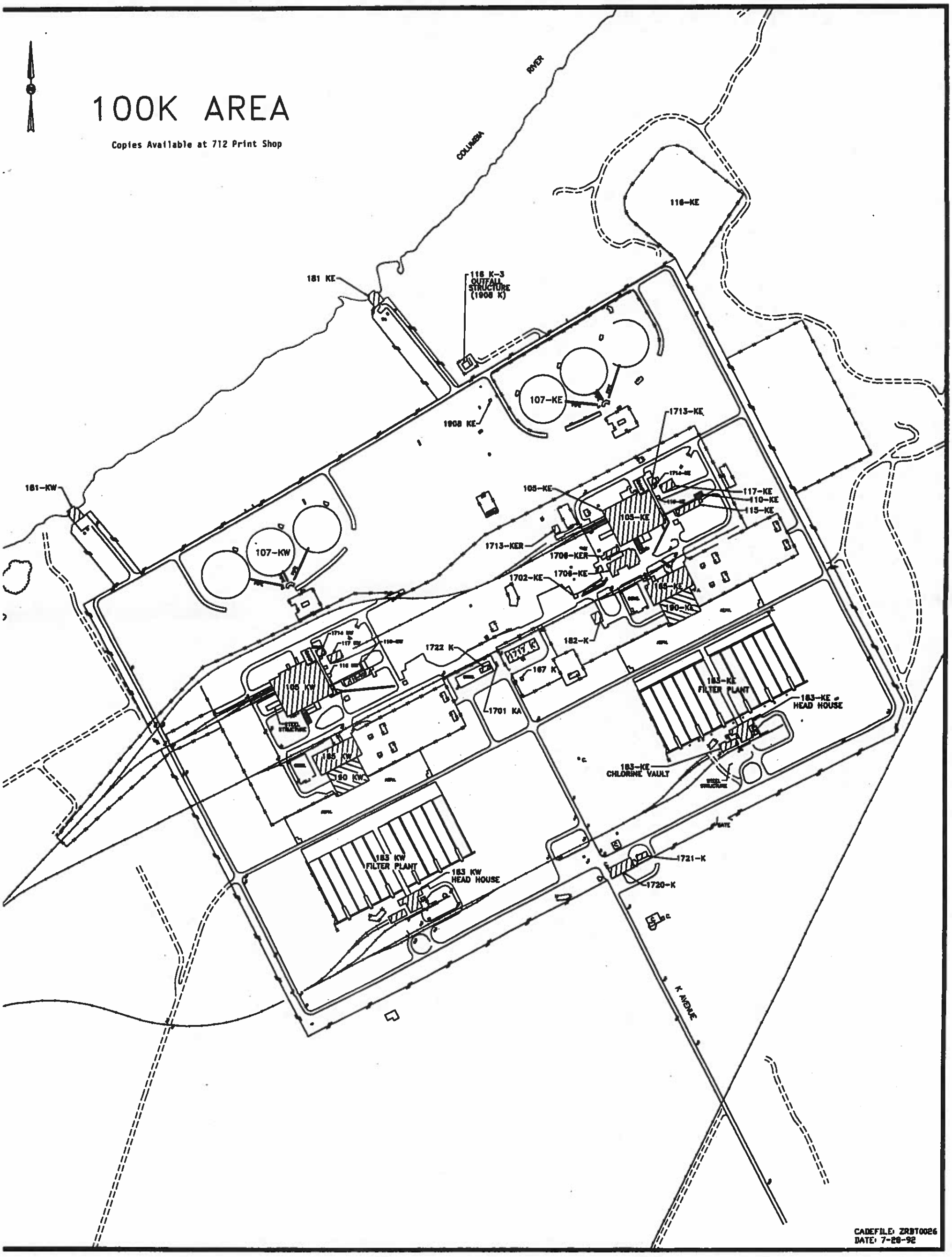

100D AREA

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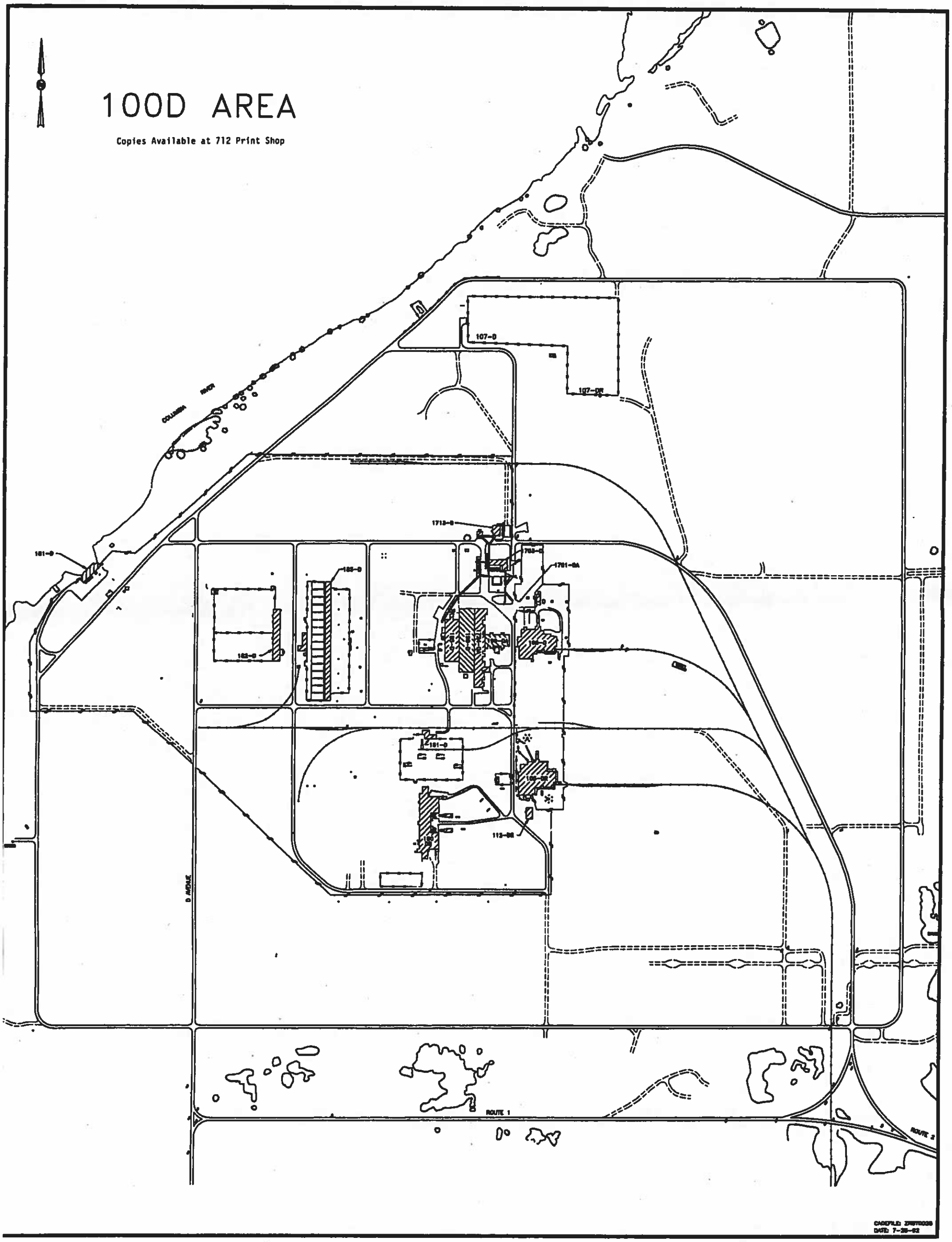

100N AREA

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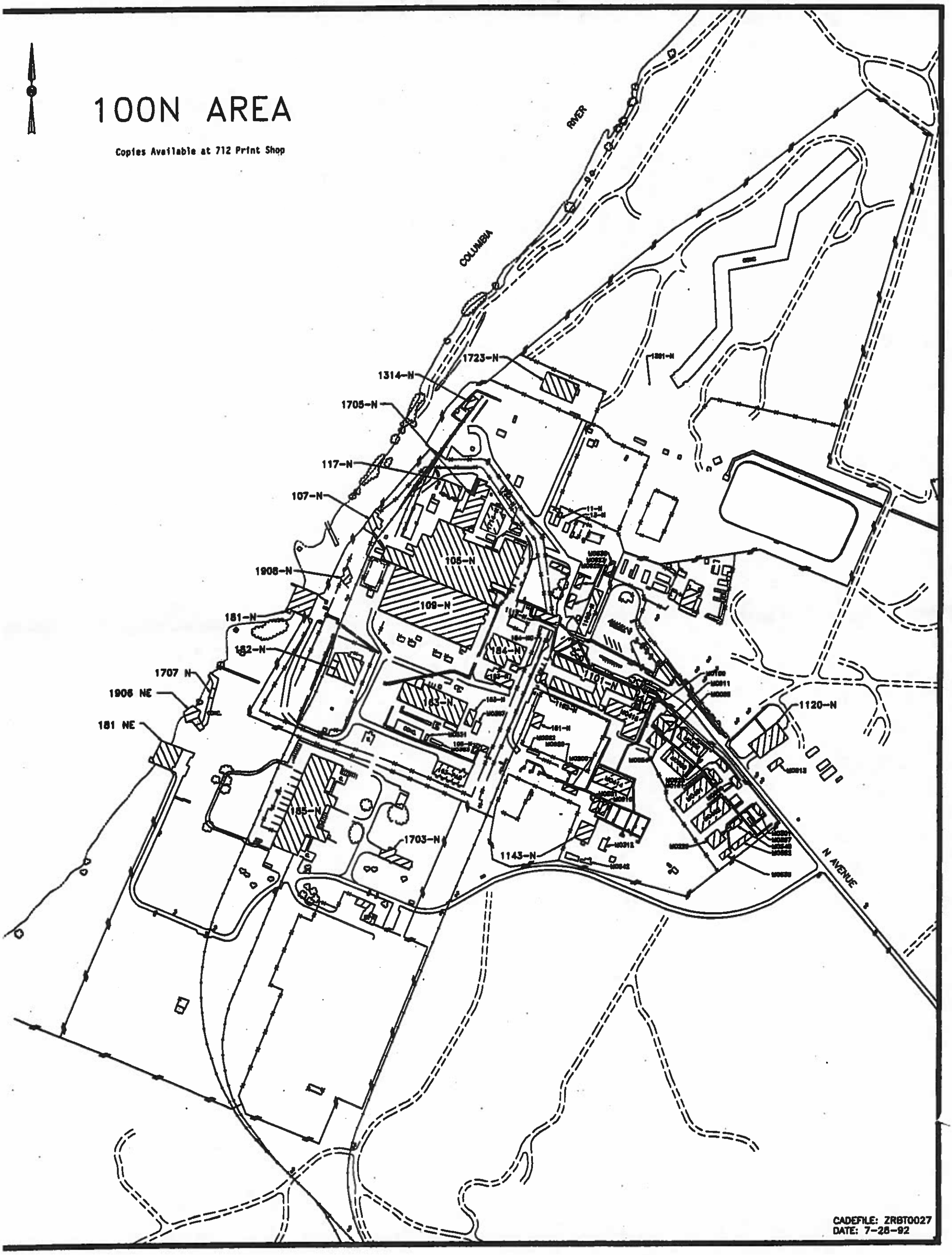

100H AREA

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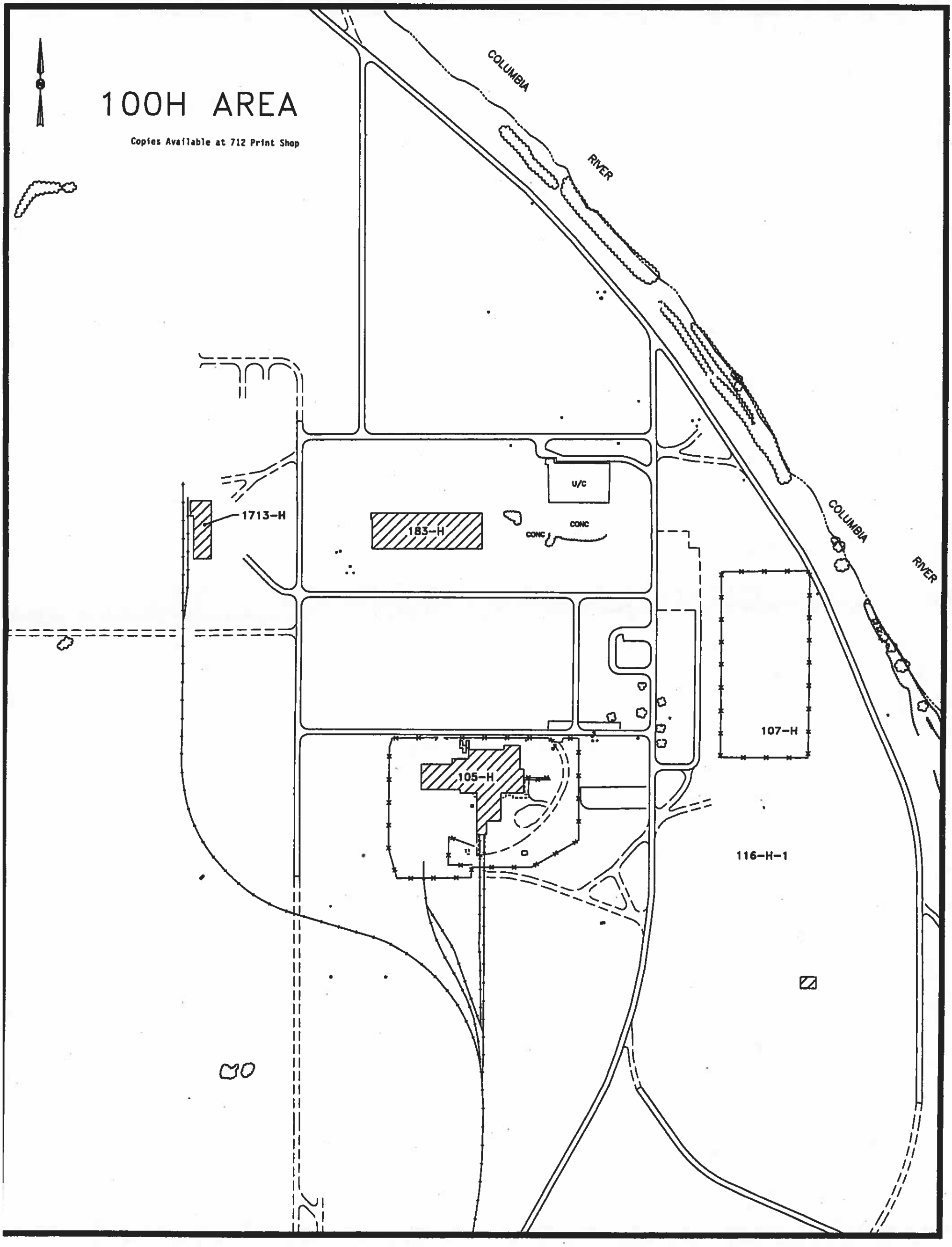

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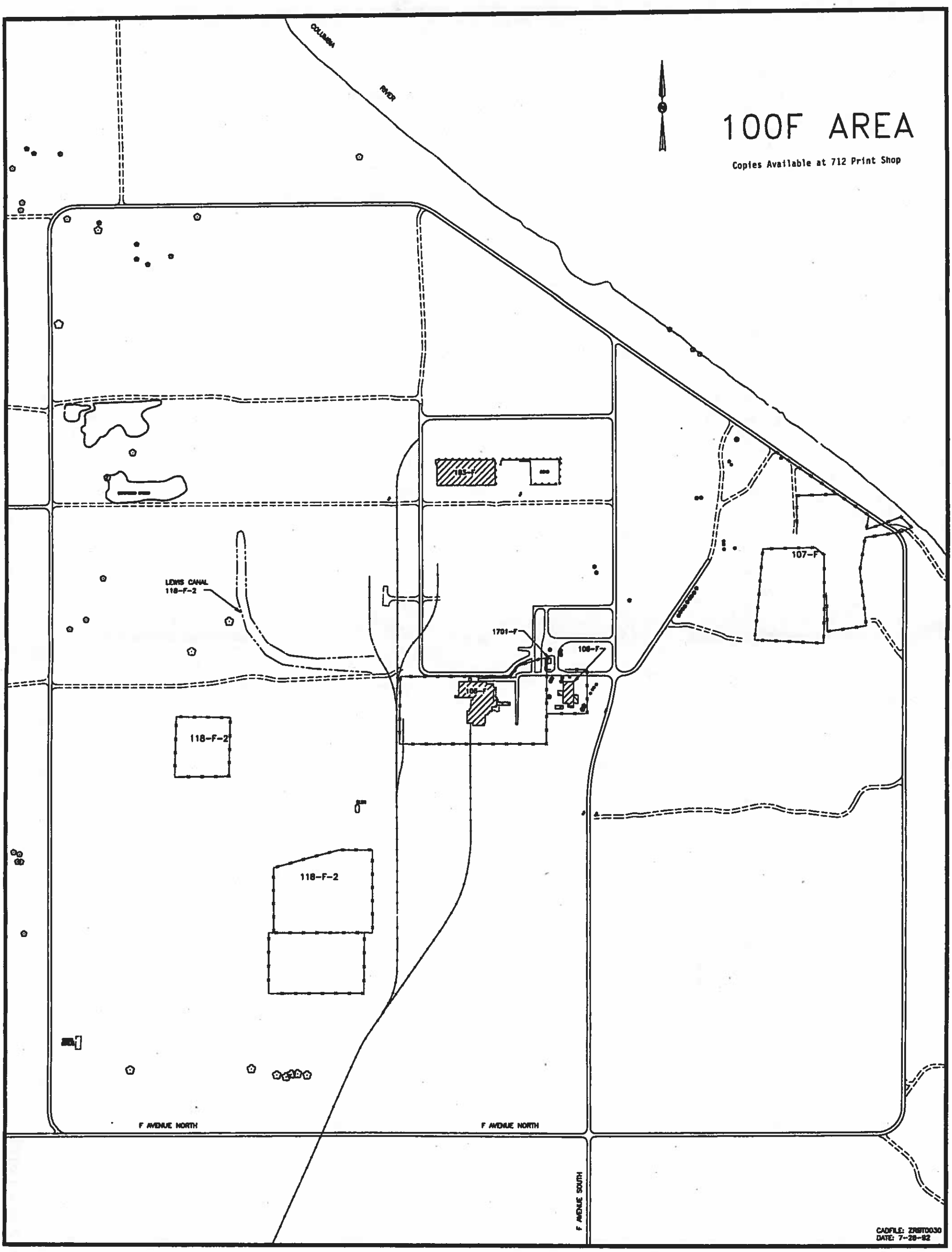
DATE: 7-28-92


100F AREA
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COLUMBIA
RIVER
LEWIS CANAL
118-F-2
1701-F
108-F
107-F
118-F-2
118-F-2
F AVENUE NORTH
F AVENUE NORTH
F AVENUE SOUTH
CADFILE: ZR9T0030
DATE: 7-20-92

attachment 2

AIR 98-607

STATE OF WASHINGTON
DEPARTMENT OF HEALTH
DIVISION OF RADIATION PROTECTION
7171 Cleanwater Lane, Bldg. 5 • P.O. Box 47827 • Olympia, Washington 98504-7827
TDD Relay 1-800-833-6388

July 6, 1998

Mr. Emad Shahin
U. S. Environmental Protection Agency
Region 10
1200 Sixth Avenue
Seattle, Washington 98101-OEA-095

Dear Mr. Shahin:

Enclosed are the inspection reports from the Washington State Department of Health (WDOH) for the May Multi-Media Inspections. The inspections were conducted jointly by teams from Environmental Protection Agency (EPA), WDOH, and Washington State Department of Ecology (WSDOE).

The reports include the following inspections:

- WRAP / CWC and TRUSF Facilities
- 222-S Laboratory
- 105 KE-Basin
- 1706 KE Laboratory Facility
- 105 N Reactor
- 324 Building
- 241 AP Tank Farm
- Waste Sampling Characterization Facility
- T-Plant
- S / SX and SY Tank Farm Complex

There were several general issues we identified during the Multi-Media Audit:

1. Many minor stacks are not being maintained at the appropriate level.

2. The failure by some facilities to transfer the conditions placed by WDOH in the approval Notices of Construction into operational practice continues to be a problem.

3. Some records are not being maintained as readily retrievable for regulatory review.

If you have any questions about these reports, please feel free to call me at (360) 236-3261, or Cindy Grant at (206) 464-6206.

Sincerely,

Allen W. Conklin, Manager
Air Emissions and Defense Waste Section
Division of Radiation Protection

AWC/jr

cc: Jerry Leitch, EPA
John Bates, FDH
Doug Sherwood, EPA
Steve Alexander, Ecology
James E. Rasmussen, DOE-RL

MULTI-MEDIA INSPECTION

Date: May 12, 1998
Facility: 222-S Laboratory Complex
E. U. Status: 296-S-21 / 296-S-16 Operational Minor Stacks

- Inspectors:

  Department of Health - John Martell, John Schmidt
  Environmental Protection Agency - Emad Shahin
  Department of Ecology – Jerry Hensley

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL-TWRS – Dennis Bowser

- Hanford Contractor Escorts:

  WMH – Russell Johnson

- 222-S Facility Escorts:

  Ron Boon, Lanny Weaver

- Facility Description:

  The 222-S Facility (REDOX Laboratory) and the 219-S Waste Tank Facilities are located in the 200-W Area of the Hanford Site. The main functions of these facilities are to receive, prepare, process, and analyze radioactive and other samples collected on the Hanford Site. The 222-S Laboratory and the 219-S Waste Tank Facility are exhausted by two separate main emission units. The 296-S-21 exhausts the 222-S Laboratory and the 296-S-16 exhausts the 219-S Waste Tank Facility.

- Inspection Description:

  <u>296-S-16 Emission Unit (219-S Facility)</u>

  The emission unit appeared to be in good shape. The sample flow rate was operating at 105 SCFH. All emissions equipment calibration stickers were dated April 10, 1998. Emissions monitoring equipment appeared to be in good condition.

Issue: HEPA filter test ports were not labeled. This is considered a "Best Management Practice" for older facilities with minor emission units that must meet the ALARACT standards.

Status: HEPA filter test ports will be labeled by May 1999. **Issue closed**

296-S-21 Emission Unit (222-S Facility)

The emission unit appeared to be in good shape except for the damage caused to the duct structural support for the back-up emission unit. The structural support, damaged by a truck in 1995, is bent and miss-shaped to the point that structural integrity is in questions.

Issue: The priority to repair the damage of the structural support needs to be addressed.

Status: Explanation was provided on May 20, 1998, by Ron Boom. There is not funding currently available to make repairs to the damaged structure. This decision to not repair the support was based on discussions with structural engineers and observation of system in operation. No structural calculations were completed on the damage support. Review of the original estimation calculations and based on "engineering judgement," the system was found to be operational in an emergency situation, but should be repaired. **Issue is Still Open**

The following information was requested from the facility to be delivered at the close of business on May 13, 1998.

- The last HEPA aerosol test, instrument calibration, and periodic confirmatory measurement record for each emission unit.

- Records documenting required monitoring during the T-7/8 tunnel clean out and the CO_2 Decontamination Facility operation.

These records were delivered and reviewed on May 13, 1998. The following issues were provided to Hector Rodriguez and Russell Johnson on May 14, 1998.

Issue: Periodic confirmatory measurement data for both emission units contain sample gaps (some as great as two days). Please explain the causes of the gaps?

Status: An explanation was provided on May 20, 1998, by Ron Boon. Gaps occur when the sampler and stack were not in operation. **Issue Closed**

Issue: Sample data for the CO_2 Decontamination Facility had on sample period that all results were zero flow and no reportable activity. Explanation requested?

Status: An explanation was provided on May 20, 1998, by Ron Boom. Flow rates were incorrectly entered. Corrections were made and new documentation was provided. **Issue Closed**

Issue: The records provided for the aerosol testing do not meet the requested data. Please provide the correct records.

Status: Explanation was provided on May 20, 1998, by Ron Boom. Testing is recorded per the procedure on the work package data sheets. **Issue Closed**

- Investigation Summary:

  Open Issue: The repair of the damaged the structural support for the back up to the 296-S-21 emission needs to be addressed.

  Currently there are no plans to replace or repair the damaged structural support. No funding is available. No structural modeling of the damaged structure has been performed. Priorities for funding have been based on engineering judgment.

All other inspection issues are closed.

MULTI-MEDIA INSPECTION

Date: May 13, 1998
Facility: 241 AP Tank Farm
E. U. Status: 296-A-40 / 296-A-42 Operational Minor Stacks

- Inspectors:

  Department of Health – Johanna Berkey, Gail Laws
  Environmental Protection Agency – Emad Shahin
  Department of Ecology – Jerry Hensley

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL-TWRS – Dennis Bowser

- Hanford Contractor Escorts:

  WMH – Russell Johnson

- AP Tank Farm Facility Escorts:

  John Guberski

- Facility Description:

  AP Tank Farm is a Double Shell Tank Farm that contains several million gallon tanks.

- Inspection Description:

  The inspectors enter the AP Tank Farm and visually inspected the two stacks monitoring cabinets. The stack cabinets were in compliance with calibration requirements.

- Issue:

  There are no issues of concern at this time for this emission unit.

- Documents Requested:

  HEPA records and procedures for the past five years.

- Investigation Summary:

  All inspection issues are closed.

MULTI-MEDIA INSPECTION

Date: May 13, 1998
Facility: Waste Sampling Characterization Facility (WSCF)
E. U. Status: 696-W-1 / 696-W-2 Operational Minor Stacks

- Inspectors:

  Department of Health – Johanna Berkey, Gail Laws
  Environmental Protection Agency – Emad Shahin
  Department of Ecology – Jerry Hensley

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL-TWRS – Dennis Bowser

- Hanford Contractor Escorts:

  WMH – Russell Johnson

- WSCF Facility Escorts:

  Jim Morrison

- Facility Description:

  WSCF is a laboratory focusing on environmental samples. The Facility completed construction in 1994 and shortly after started analyzing air samples, soil and water samples on the Hanford Site.

- Inspection Description:

  A Notice of Construction (NOC) verification inspection was conducted. This inspection involves examining of the NOC and verifying that the facility meets all the requirements for this NOC. This specific NOC was approved by WDOH in 1990. The current regulations came into effect on April 21, 1994. The inspectors discussed the process description, control technologies, stack monitoring and source term inventory.

  <u>696-W-1 Emission Unit (Main Building)</u>

  The emission unit ventilates the main building and is considered the main stack for the Facility.

Issue: The inspection walk-down occurred one day prior to the calibration expiration date for the stack monitoring cabinet instrumentation. The inspection team pointed out that the calibration was only good for one more day and that they want to ensure

that the instrumentation was calibrated prior to the completion of this audit. The inspectors reviewed a work package for calibrating the instrument on May 22, 1998. The inspectors will re-inspect the facility to verify that the instruments are calibrated.

696-W-2 Emission Unit (WSCF)

Issue: There were no areas of concern form this emission unit.

- Information Requested from the Facility:

  - Radionuclide Inventory (Liquid Standards: Opened)
  - Stack Sample Probe Schematics

All documents requested were received in a timely manner.

- Investigation Summary:

  All Inspections Issues are Closed.

MULTI-MEDIA INSPECTION

Date: May 13, 1998
Facility: T Plant Complex
E. U. Status: 291-T-1 / 296-T-7 / 296-T-13 Operational Minor Stacks

- Inspectors:

  Department of Health – Johanna Berkey, Gail Laws
  Environmental Protection Agency – Emad Shahin
  Department of Ecology – Jerry Hensley

- Department of Energy Escorts:

  WMH – Russell Johnson

- T Plant Facility Escorts:

  Brett Barnes

- Facility Description:

  T Plant is an old shutdown separations facility that stopped operating in 1952. The facility currently decontaminates large equipment for free release. The facility also stores large contaminated equipment.

- Inspection Description:

  This inspection included a quick visual tour of the outside of the facility and examination of the main stack cabinet (296-T-1). The HEPA filter banks were reviewed briefly. Time was limited. The inspection team felt the visual inspection was adequate for this facility. All instrumentation located in the stack cabinet were in calibration.

No records or documents were requested during this inspection.

- Investigation Summary:

  There are no open inspection issues.

MULTI-MEDIA INSPECTION

Date: May 14, 1998
Facility: S/SX/SY Tank Farm Complex
E. U. Status: 296-S-15 (SX Primary), 296-P-23 (SY Primary, 296-P-28 (SY Back-up) 296-S-18 (242 Evaporator Building Exhaust) Operational Minor Stacks

- Inspectors:

  Department of Health – John Martell, John Schmidt
  Environmental Protection Agency – Emad Shahin

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez

- Hanford Contractor Escorts:

  'WMH – Russell Johnson

- S/SX/SY Tank Farm Facility Escorts:

  Phil Miller, Scott Conrad, Ron Tucker

- Facility Description:

  The S/SX/SY Tank Farms are located in the 200 West Area of the Hanford Site. These facilities consist of multiple single and double shell tanks used to contain radioactive waste from various facilities located on the Hanford Site. Current activities being conducted in the Tank Farm Complex are general operations, rotary and push mode core sampling of tank waste. Four active emission units were inspected. The 296-S-15; which exhausts the SX high heat tanks; the 296-P-23 and P-28 are able exhausters; which act as the primary and back-up exhauster for the SY Tank Farm; 296-S-18; which exhausts the shut-down 242-S Evaporator Building. The following tank passive emission units were also inspected: 104-SX, 104-S, and 108-S.

- Inspection Description:

  <u>296-S-15 Emission Unit (241-SX Tank Farm)</u>

  The emission unit appeared to be in good shape. The sample flow rate was operating at 87 standard cubic feet per hour (SCFH).

296-P-23/P-28 Emission Unit (241-SY Tank Farm)

The emission unit appeared to be in good shape. The sample flow rate was operating at 120 standard feet per hour (SCFH). Emissions monitoring equipment appeared to be in good condition.

296-S-18 Emission Unit (242-S Evaporator Building Exhaust)

The emission unit was not functioning due to the fan being shut off. The emission unit was in good shape except for excessive deterioration of the flex connections between the fan housing and the HEPA filter housing, aerosol test ports that were not covered, and contamination control devices not properly attached to the damper control handles. Emissions monitoring equipment appeared to be in good condition.

Issue: The flex connections should be maintained to prevent failure of the emission unit. "Best Management Practice" (BMP) for minor emission units build prior to March 4, 1994, and must meet the ALARACT Standard.

Status: Steel tape is being applied to the flex connections as a temporary fix. Work package 2W-98-0888 has been generated for a permanent fix. Completion date: December 31, 1998. **Issue Closed**

Issue: The test ports should be "capped" to prevent under estimating of emissions. BMP for minor emission units built prior to March 4, 1994, and must meet the ALARACT Standard.

Status: The test ports will be "capped" with steel tape. Action to be completed by May 29, 1998. **Issue Closed**

Issue: The contamination control device (plastic sleeve) on the damper controls was not attached. The passive emissions to the environment should be controlled. BMP for minor emission units built prior to March 4, 1994, and must meet the ALARACT Standard.

Status: The sleeving problem will be corrected by May 29, 1998. **Issue Closed**

Issue: HEPA filter test ports were not labeled. This is considered a BMP for minor emission units built prior to March 4, 1994, and must met the ALARACT Standard.

Status: The HEPA filter test ports will be labeled for the SX and SY exhauster by July 31, 1998. **Issue Closed**

- The following information was requested from the facility to be delivered at the close of business May 18, 1998.

  - The last HEPA aerosol test, instrument calibration, and periodic confirmatory measurement record for each emission unit.

  - The last HEPA aerosol test for the 104-SX, 104-S and 108-S passive emission unit.

The requested information was delivered on May 14, 1998.

The following additional information was requested.

Email May 15, 1998 – Phil/Scott

Listed below are some issues with our walkdown:

296-S-18

The emission unit was not functioning due to the fan being shut off. (Scott, could you let us know why?) The emission unit was in good shape except for excessive deterioration of the flex connections between the fan housing and the HEPA filter housing, aerosol test ports that were not covered, and contamination control devices not properly attached to the damper control handles. Emission monitoring equipment appeared to be in good condition.

Issue: The flex connections should be maintained to prevent failure of the emission unit. BMP for minor emission units built prior to March 4, 1994.

Issue: The test ports should be "capped" to prevent under estimating of emission. BMP for minor emission units build prior to March 4, 1994.

Issue: The contamination control device (plastic sleeve) on the damper controls were not attached. The passive emissions to the environment should be controlled. BMP for minor emission units built prior to March 4, 1994.

Issue: HEPA filter test ports were not labeled. This is considered a BMP for minor emission units built prior to March 4, 1994.

The last issue would also apply to the other emission units.

296-S-18 was shutdown on May 6, 1998, due to failure of the record sampler. The sample system failed due to the failure of a pressure switch. A replacement pressure switch has been ordered but not yet received. Once the switch is received, repairs will be completed and the exhauster returned to service.

The other issues are being looked into and will be take care of:

Email from Phil Miller received May 18, 1998.

- Review Follow-Up Requests:

  A review of the information resulted in the request for clarification of the periodic sampling data for the 296-S-15 emission unit. Sample gaps exist during periods of operation of the RMCS in the SX Tank Farm Complex. A Notice of Construction condition of operation of the RMCS in SX Tank Farm was that the emission unit (296-S-15) would operate continuously during the RMCS operation. There appears to be a 52.4 hour gap during the sample period from 12-10-97 to 12-23-97, during which time the RMCS truck operated for several days. Additional review of

the daily operational logs for the 296-S-15 exhauster record sampler revealed the record sampler was functional during the days the RMCS truck was in operation.

No other issues were identified.

- Investigation Summary:

  All repair items noted in this report will be verified during future inspections to insure their completion.

All inspection issues are closed.

MULTI-MEDIA INSPECTION

Date: May 14, 1998
Facility: 105 K-East Basin
E. U. Status: 100K-P105KE 001, 2, 3, 4 Operational Minor Stacks

- Inspectors:

  Department of Health – John Martell, John Schmidt
  Environmental Protection Agency – Emad Shahin

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL-TWRS – Dennis Bowser

- Hanford Contractor Escorts:

  WMH – Russell Johnson

- KE-Basin Facility Escorts:

  Rick Gant, Dave Watson, Jerry Hunacek

- Facility Description:

  The 105 K-East Basin Facility (KE-Basin) is located in the 100-K Area of the Hanford Site. The main function of this facility is to store spent nuclear fuel from the 100-N Reactor. The fuel elements are stored in canisters underwater, which provides a cooling mechanism for the fuel as well as radiation shielding for personnel and environmental purposes. The facility is currently in the process of preparing to remove the fuel from the basin, place it in a more stable configuration and place it in permanent storage in the 200 Areas.

  The KE-Basin is ventilated through four ceiling fans and vents, however there is no HEPA filtration provided on these units. The control of radionuclide emissions is provided by water which covers the fuel elements. In addition the water is chilled, and filtered to keep radionuclide concentrations low.

  Three ambient air samplers located near the entrance to the ceiling fans monitor emissions from the KE-Basin. The filter paper on these samplers is exchanged weekly and analyzed for radionuclides.

- Inspection Description:

  100K-P105KE 001,2,3,4 Emission Unit (KE-Basin)

  The emission unit appeared to be in good condition, all ambient air samplers were in operation and in current calibration (expire October 28, 1998). A glovebox was set up in the basin to perform above water work on empty fuel canisters, and appeared to be in acceptable condition. There were also two portable HEPA filter ventilation units in the basin. Neither unit was in operation, and appeared to be adequately contained to stop any potential fugitive emissions.

- The following information was requested from the facility to be delivered at the close of business May 18, 1998:

  - The last HEPA aerosol test from the two portable ventilation units, the last two months of periodic confirmatory measurements, calibration records of the ambient air samplers.

  - Work place air monitoring and pre-job radiation surveys for the 105-KE and KW corridor 7 modifications as required by the Routine Technical Assistance Meetings of November 12, 1996. These records were delivered and reviewed on May 19, 1998

No issues were identified at the KE-Basin.

- Investigation Summary:

  All inspection issues are closed.

MULTI-MEDIA INSPECTION

Date: May 15, 1998
Facility: 324 Building
E. U. Status: EP-324-01-S Operational Major Stack

- Inspectors:

  Department of Health – Johanna Berkey, Gail Laws
  Environmental Protection Agency – Emad Shahin
  Department of Ecology – Jerry Hensley

- Department of Energy Escorts:

  DOE/RL – Hector Rodriguez
  DOE/RL-TWRS PD – Dennis Bowser
  DOE/RL-324 – Bryant Charbeneau

- Hanford Contractor Escorts:

  WMH – Russell Johnson

- 324 Facility Escorts:

  Dan Johnson, Dave Rasmussen, Ron Gouls (PNNL), Steve Jette (PNNL)

- Facility Description:

  The mission of the 324 Building recently changed from a research and development facility to a facility undergoing decommissioning. Fluor Daniel Hanford Company owns and operates the facility. PNNL manages projects within the 324 Building. The stack monitoring system continuously monitors for alpha and beta. A tritium sampler also monitors stack emissions.

- Inspection Description:

  This inspection scope was an overview of the projects currently operating within this facility and the recent Notice of Violation (NOV) issued by the Department of Health. We reviewed the Plasma Arc Furnace activities and its operations, including a visual inspection of the Plasma Arc Furnace. The Plasma Arc Furnace NOC conditions were the only issues addressed at this time. The stack monitoring system was reviewed and found in compliance with the regulations.

- Requested Documents:

  Chain-of-Custody for Tritium Samples

All items requested were received in a timely manner.

- Investigation Summary:

  All Inspection issues are closed.

MULTI-MEDIA INSPECTION

Date: May 18, 1998
Facility: WRAP/CWC/TRUSAF
E. U. Status: 296-W-04 WRAP Pre-Operational Major and Minor Passive Emissions Units

- Inspectors:

  Department of Health – John Martell, Cindy Grant, John Schmidt

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL PD – Mark French

- Hanford Contractor Escorts:

  WMH – Tom Frazier

- WRAP Facility Escorts:

  Harlan Boynton, Jay Bottenus, Lee Roberts, Mike Hackworth

- CWC/TRUSAF

  Brett Barnes

- Facility Description:

  The WRAP/CWC/TRUSAF Facilities are located in the 200 West Area of the Hanford Site. The WRAP Facility consists of a ventilated structure in which waste is scheduled to be non-destructive analysis (NDA) performed, repackaged, and/or compacted. WRAP is currently scheduled for start-up the Summer of 1998. The CWC acts as a series of facilities for storage of containerized waste and is currently active. Waste from CWC will be shipped to WRAP for disposition. The TRUSAF Facility has recently had all containerized waste removed from the facility. Due to residual contamination, the emission unit remains active.

- Inspection Description:

  <u>296-W-4 Emission Unit (WRAP Facility)</u>

  This is a registered as a major emission unit. The emission unit appeared to be in excellent shape. The emissions monitoring equipment appeared to be in good condition.

Central Waste Complex (CWC)

This emission unit is currently a minor emission unit. The vents (passive point sources of emissions) are monitored by smears indicating control of the stored material. The near-field monitor, N-964 monitors the facilities for diffuse/fugitive emissions.

Issue: The monitoring of the low-flash point storage facilities revealed that the sample probe was installed incorrectly on the eastern building.

Status: Sample probe has been returned to the correct configuration. **Issue Closed**

Issue: A request was made during the inspection to provide documentation verifying CWC was below their annual possession quantity of Pu-239 does not exceed 2.92E-2 PE (plutonium equivalent) curies, and the annual abated emission limits can not exceed that provided by 1.46E-6 PE curies.

Status: On May 28, 1998, DOE notified the Department of Health the CWC inventory for plutonium equivalent (PE) curies exceeded the NOC document DOE-RL-95-79 Rev. 0 criteria. DOH met with DOE contractor personnel on June 1, 1998, and received updated information on the current CWC NOC. DIE contractors have currently stopped receiving vented containers at the CWC until this issue can be cleared up. Review of the facility radiological surveys, and air monitoring results for ambient air monitor N-964 indicate that radionuclide air concentrations have been at or near ambient levels. The facility is currently pursuing a modification to the current Notice of Construction. **Issue is Still Open**

296-T-11/12 Emission Unit (244-T TRUSAF)

The emission unit was in good shape. Only 296-T-12 was operational. Emissions monitoring equipment appeared to be in good condition.

- The following information was requested from the facility to be delivered at the close of business May 18, 1998: (All information was received)

  - For WRAP no records requested, non-operational.
  - For the CWC the smear and fixed head sample data for February 1998 and June 1997, confirmation of the current inventory.
  - For 296-T-12 the last HEPA aerosol test, instrument calibration, and periodic confirmatory measurement record for each emission unit.

- Investigation Summary:

  Open Issue: DOE notified Department of Health that the CWC inventory of the plutonium equivalent (PE) curies exceeded the NOC document DOE-RL-95-79 Rev. 0 criteria. On June 1, 1998, DOH received from DOE contractor personnel updated information on the current CWC inventory. DOE contractors have currently stopped receiving vented containers at the CWC until this issue can be cleared up. Review of ambient air monitor N-964 surveys indicate that radionuclide air concentrations have been at or near ambient levels. The facility is currently pursuing a modification to the current NOC to reflect these conditions.

MULTI-MEDIA INSPECTION

Date: May 19, 1998
Facility: 1706 KE-Laboratory Inspection and Emission Units
E. U. Status: 1706 KE Operational Minor Stack

- Inspectors:

  Department of Health - Cindy Grant, Johanna Berkey
  Department of Ecology - Bob Wilson

- Department of Energy Escorts:

  DOE/RL -- Hector Rodriguez, Dennis Bowser

- Hanford Contractor Escorts:

  WMH - Tom Frazier, Rod Jochen

- 1706 KE Facility Escorts:

  DESH - Tom Bratrod, Steven Burke, Jerry Kurtz, Gary Stevens, Rick Gant, David Watson

- Facility Description:

  The laboratory performs nondestructive radioactivity analysis. It analyzes work place air samples, fixed head air samples (job coverage), filter paper, waters, and ground water samples.

- Laboratory Analytical Capabilities:

  Gross Alpha, Gross Beta, Gamma, Tritium in Water

  Sample Media - Air, Water, Wipes and Soil

  Quantity -- Perform approximately 2,800 - 3,000 analysis per year. Most analysis are to support 100 KE area activities

- Inspection Description:

  Emission Unit 1706 KE was inspected. The tube to the sampling line was pointing out of the stack. We reviewed the work package 1K-98-01311/H that was submitted on April 22, 1998 to re-attach the line. The repair is scheduled to be completed within the next month.

- Monthly stack samples are collected. One sample is analyzed per quarter.

  A grab air sample from 241-SX-105 Riser 15 collected on March 17, 1998, was selected to evaluate the laboratory's procedures. This grab air sample was used to confirm a release on 241-SX-105. This sample was used to verify chain-of-custody, analytical capabilities, and equipment performance of the 1706 KE-Laboratory. We reviewed the analytical report of that sample and followed it through the analytical process. The calibration, efficiency, and instrument counting procedures were reviewed. The instrumentation was operating properly during the time of sample analysis. The results of the past two proficiencies testing rounds were checked. The laboratory's performance was satisfactory.

- Information Requested from the Facility:

  - Work Package on 1706 KE Stack Probe repair order;
  - Last two results of the EPA and EMSL Laboratory Inter-comparison Studies;
  - Sample Analysis Report for SX-105 Riser 15 collected 3/17/98;
  - Chain-of-Custody for SX-105 Riser 15 collected 3/17/98;
  - KE Counting Laboratory Sample receiving procedure.

All information was received by the close of business on May 20, 1998. All instrumentation was in operating condition during the analysis of the sample. The chain-of-custody of the sample was adequate. The laboratory performs limited analytical procedures. The analyses they do perform seem to be done well.

- Investigation Summary:

  No Inspection Issues Identified.

MULTI-MEDIA INSPECTION

Date: May 19, 1998
Facility: 105 N Reactor
E. U. Status: N 116 Stack Operational Minor Stack

- Inspectors:

  Department of Health – Johanna Berkey, Cindy Grant
  Department of Ecology – Bob Wilson

- Department of Energy Escorts:

  DOE/RL-EAP – Hector Rodriguez
  DOE/RL-TWRS – Dennis Bowser

- Hanford Contractor Escorts:

  ERC – Ray Collins
  ERC – Joe Zoric

- 105 N Reactor Facility Escorts:

  Tom Logan

- Facility Description:

  The 105 N Reactor is a retired plutonium and steam-producing reactor. The reactor stopped operating in 1987 and went to cold standby in 1989. The reactor contains fuel fragments, sediment, and basin water. The N Basin is under an aggressive cleanup campaign to clean up the basin and remove all basin water, sediment, and fuel fragments by July 31, 1998. The N complex consists of several buildings and then the main reactor building.

- Inspection Description:

  The inspectors reviewed the N Stabilization NOC, approved in 1994 by the Department of Health. The NOC granted approval for several activities taking place in the Basin. The Basin activities currently require workers to be wearing a mask. Entry requires that individuals must have a bioassay analysis and mask fit prior to entry. The inspectors did not enter the Basin. Video cameras were setup in the N Basin. We did view the work in progress from a monitor outside of the Basin. The inspectors also reviewed future activities that will take place in the next several months and their potential permitting requirements.

Issue: Inspection of the air monitoring cabinet revealed that the vacuum gauge calibration sticker stated it was calibrated in 1998 and was due 1997. A review of the

records revealed that the calibration date was 1998 and the due date as 1999. It appears that was a transcription error. **Issue Closed**

- Requested Documents:

  Survey Records for the Monoliths
  Final Sediment Total Activity and Quantities

All items requested were received in a timely manner.

- Investigation Summary:

  All inspection issues are closed.

Attachment 3

NOTICE OF CONSTRUCTION

200/300 AREA STEAM PLANT REPLACEMENT

Submitted to:

Washington State Department of Ecology
Olympia, Washington

On behalf of:

United States Department of Energy
Richland Operations Office
Richland, Washington

Prepared by:

Tim W. Sonnichsen, P.E.

CARNOT

Woodinville, Washington

March 17, 1997

SUMMARY

The United States Department of Energy, Richland Operations Office (DOE/RL), intends to install approximately forty-one new boilers in the 200 East, 200 West, and 300 Areas on the Hanford Site. The new boilers will range in size from 10 BHP to 700 BHP corresponding to a maximum heat input rate per boiler of approximately 0.4 mmBtu/hr to 26.3 mmBtu/hr. The boilers will replace the existing steam generation equipment and will be operated and maintained by Johnson Controls Inc. ("The Contractor") under contract with DOE/RL.

The new boilers will provide several benefits. The changing nature of the site has resulted in a continual decline in steam demand. The new boiler will assist in minimizing energy consumption by being fully automatic, appropriately sized for the steam demands, and located near the steam end use. The expected fuel and operating costs savings are significant. Installation of the new boilers will also reduce air pollution emissions.

Construction is scheduled to begin in late spring of 1997 and be completed in approximately one year. Each boiler will be installed, started-up and commissioned within a 180 day period. The existing boilers will be permanently shutdown as the project proceeds.

The use of conventional "firetube" boilers is being considered. For this design, the sophistication of the combustion and emission controls will vary with the boilers' size. The larger boilers with heat input rates equal to or greater than 5 mmBtu/hr will fire continuously and modulate over a specified turndown range. These boilers will be equipped with low-NO_X burners and flue gas recirculation (FGR) which has been determined to be "best available control technology" (BACT) for NO_X. The total installed capacity of these boilers is over 80% of the total for all forty-one new boilers.

Smaller boilers with heat input rates less than 5 mmBtu/hr will use conventional burners and may have limited turndown. Clean fuels (low sulfur distillate oil in the 200 Areas and natural gas in the 300 Areas) and good combustion practices will be used to minimize emissions on all boilers.

A PSD Review for the boiler installations will not be required. No adverse ambient air quality impacts at the site fenceline are expected from the release of the very trace quantities of formaldehyde. Supporting information for these conclusions is presented in this document.

Maximum emission levels as guaranteed by the boiler manufacturer are summarized in Table S-1. A compliance assurance plan is presented involving emission testing during startup on selected boilers to certify compliance with these guarantees. Subsequent source tests are to be conducted on selected boilers once every five years. The Contractor will keep appropriate operating and maintenance records. These data will be used by DOE/RL/The Contractor to calculate individual boiler emission inventories. Annual reports will be submitted by DOE/RL/The Contractor to Ecology consistent with current practices.

TABLE S-1

PROPOSED EMISSION LIMITS
HANFORD 200/300 AREA STEAM PLANT REPLACEMENTS

Boilers With Heat Input Ratings Greater Than or Equal to 5 mmBtu/hr

No. 2 Distillate Oil-Fired	lb/mmBtu	Other Units
NO_X	0.150*	115 ppm @ 3% O_2
CO	0.071*	90 ppm @ 3% O_2
Particulate Matter (PM_{10})	0.011*	
VOC's (TOC)	0.013*	30 ppm @ 3% O_2
Sulfur Dioxides	0.051	0.05% sulfur fuel oil

Natural Gas-Fired	lb/mmBtu	Other Units
NO_X	0.037*	30 ppm @ 3% O_2
CO	0.225*	300 ppm @ 3% O_2
Particulate Matter (PM_{10})	0.012*	
VOC's (TOC)	0.013*	30 ppm @ 3% O_2
Sulfur Dioxides	0.0006	

Boilers With Heat Input Ratings Below 5 mmBtu/hr

No emission limits.

Notes

* Guaranteed by the boiler manufacturer with specified distillate oil fuel.

Commercially available low-sulfur distillate oil fuel will be used in the 200 Areas.

Natural gas will be used in the 300 Area.

All boilers will be operated and maintained using "good combustion practices."

TABLE OF CONTENTS

		Page
1.0	INTRODUCTION	1
1.1	PROJECT SCOPE	1
1.2	IDENTIFICATION OF SITE OWNER AND OPERATOR	1
1.3	DESCRIPTION OF CHANGES	2
2.0	BACKGROUND INFORMATION	5
2.1	HANFORD SITE	5
2.2	EXISTING BOILER DESCRIPTIONS	5
2.3	CURRENT EMISSION INVENTORIES	10
2.4	COMPLIANCE WITH REQUIREMENTS	10
3.0	PLANNED NEW BOILER INSTALLATIONS	13
3.1	BOILER DESCRIPTIONS	13
3.2	FIRING EQUIPMENT	13
3.3	FUELS	13
3.4	LOCATIONS	16
3.5	POTENTIAL TO EMIT	16
4.0	EMISSIONS NETTING ANALYSES	25
4.1	NETTING PROCEDURES	25
4.2	NETTING ANALYSES FOR NO_X AND CO	26
5.0	BACT DETERMINATIONS FOR NO_X AND SO_2	31
5.1	AVAILABLE NO_X CONTROL TECHNOLOGIES	32
5.2	NO_X CONTROL TECHNICAL FEASIBILITY ANALYSES	37
5.3	NO_X CONTROL COST-EFFECTIVENESS ANALYSES	40
5.4	DETERMINATION OF BACT FOR NO_X	45
5.5	AVAILABLE SO_2 CONTROL TECHNOLOGIES	46
5.6	SO_2 CONTROL TECHNICAL FEASIBILITY ANALYSES	46
5.7	SO_2 CONTROL COST-EFFECTIVENESS ANALYSES	47
5.8	DETERMINATION OF BACT FOR SO_2	47
6.0	FORMALDEHYDE AIR QUALITY ANALYSIS	49
6.1	APPROACH	49
6.2	RESULTS OF THE SCREEN-3 CALCULATIONS	50
7.0	COMPLIANCE ASSURANCE PLAN	53
7.1	STARTUP COMPLIANCE TESTS	54
7.2	COMPLIANCE ASSURANCE	55
7.3	RECORDKEEPING	55
7.4	REPORTING	56

APPENDIXES

A ANNUAL EMISSION INVENTORIES (1986 - 1995)

B NEW BOILER EMISSION INVENTORY

C QUARTERLY EMISSION INVENTORIES

D CARB RACT AND BARCT DOCUMENT

E DISTILLATE FUEL OIL ANALYSES

AMOCO FUEL OIL IS AVAILABLE IN THE RICHLAND AREA

U.S. OIL & REFINING FUEL OIL IS NOT AVAILABLE IN THE RICHLAND AREA

F INFORMATION FROM CLEAVER-BROOKS

G INFORMATION FROM VENTURA COUNTY APCD

LIST OF TABLES

Table		Page
S-1	Proposed Emission Limits Hanford Steam Plant Replacements	
2-1	Hanford Site Boiler Descriptions (August 1996)	7
2-2	Hanford Site Boilers Annual Criteria Pollutant Emission Inventories (t/y)	11
3-1	Planned Boiler Additions	14
3-2	Boiler Locations in the 200 Areas	17
3-3	Boiler Locations in the 300 Area	18
3-4	Emission Factors Used	19
3-5	New Boilers' Potential To Emit (t/y)	20
4-1	Boiler Changes During the Contemporaneous Period	27
4-2	Contemporaneous NO_X Emission Change Summary	29
4-3	Contemporaneous CO Emission Change Summary	30
5-1	Combustion Based NO_X Control Technologies	34
5-2	NO_X Control Technology Feasibility Summary	38
5-3	Cost-Effectiveness of NO_X Emission Control Technologies Boilers With Heat Input Rates of 3.5 mmBtu/hr	42
5-4	Top-Down BACT Impact Analysis for NO_X Natural Gas-Fired Boiler With 12 mmBtu/hr Heat Input (300 BHP)	43
5-5	Top-Down BACT Impact Analysis for NO_X Distillate Oil-Fired Boiler With 26 mmBtu/hr Heat Input (700 BHP)	44
5-6	Top-Down BACT Impact Analysis for SO_2 Distillate Oil-Fired Boiler With 26 mmBtu/hr Heat Input (700 BHP)	48
6-1	Screen-3 Modeling Input - Stack Geometry and Flow Conditions	51
6-2	Maximum Receptor Level Annual Concentrations ($\mu g/m^3$)	52

Appendix A	A-1	Annual NO_X Emission Inventories (1986 - 1995)
	A-2	Annual SO_2 Emission Inventories (1986 - 1995)
	A-3	Annual CO Emission Inventories (1986 - 1995)
	A-4	Annual PM_{10} Emission Inventories (1986 - 1995)
	A-5	Annual PM Emission Inventories (1986 - 1995)
	A-6	Annual VOC Emission Inventories (1986 - 1995)
	A-7	Annual Lead Emission Inventories (1986 - 1995)
Appendix C	C-1	NO_X Emission Quarterly Inventories (July 1994 - June 1996)
	C-2	CO Emission Quarterly Inventories (July 1994 - June 1996)

LIST OF FIGURES

Figure		Page
2-1	Hanford Site Map	6
3-1	Firetube Boiler	15
3-2	200 West Area	Following 18
3-3	200 East Area	Following 18
3-4	300 Area	Following 18

LIST OF ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AEC	Atomic Energy Commission
APCD	Air Pollution Control District
BACT	Best Available Control Technology
BHP	boiler horsepower
BOOS	burners out of service
Btu	British thermal units
CAA	Clean Air Act
CARB	California Air Resources Board
DNSRM	Draft New Source Review Manual
DOE/RL	United States Department of Energy - Richland Operations
ECM	energy conservation measures
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
ERDA	Energy Research and Development Administration
FGR	flue gas recirculation
ft	foot
g	gram
gal	gallon
hr	hour
klb/hr	thousand pound per hour
lb	pounds
LEA	low excess air
LNB	low NO_x burner
m	meter
mm	millimeter
mmBtu/hr	million Btu per hour
μ	micro
N_2	molecular nitrogen
NOC	Notice of Construction
NO_x	nitrogen oxides
NSR	normalized stoichiometric ratio
O&M	operating and maintenance
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
ppm	parts per million
psi	pounds per square inch
psig	pounds per square inch gauge
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SNCR	selective non-catalytic reduction
t	ton
TOC	total organic compounds
VOC's	volatile organic compounds

SECTION 1.0

INTRODUCTION

1.1 PROJECT SCOPE

DOE/RL has contracted with Johnson Controls, Inc. to provide replacement energy conservation measures (ECM's) at the Hanford Site. Included in the ECM's is the decentralization of the existing power plants in the 200 and 300 Areas. The several large coal and oil-fired boilers that service these areas will be replaced with approximately forty-one new boilers firing either natural gas or low sulfur distillate oil.

The new boilers will be located in new annex buildings adjacent or in close proximity to the steam's end use. The annex buildings will house individual and, in some cases, multiple boilers. A limited number of portable boilers will also be used.

Steam is used at the site for building heat and process needs. Operations of the boilers will be monitored and controlled from a central control facility located in the 300 Area. Data from the facilities using the steam will be collected and used as the basis for starting and stopping individual boilers and for regulating the firing rates of the larger boilers.

Fuel use by each boiler will be metered and recorded on a regular basis. Boiler emission rates will be inventoried on the basis of fuel consumption and the emission factors presented in the NOC.

Energy consumption and air pollution emission rates from the Hanford Site have steadily declined over the last decade. The decentralization of the power plants and the change from generating steam using coal and residual oil to cleaner fuels will facilitate this process.

1.2 IDENTIFICATION OF SITE OWNER AND OPERATOR

Approval of the NOC is to be issued to:

Mr. William A. Rutherford 509 - 376 - 7597
Site Infrastructure Division Director
U.S. Department of Energy
Richland Operations Office
P.O. Box 550
Richland, Washington 99352

1.3 DESCRIPTION OF CHANGES

Included in the new boiler installations will be the following:

200 West Area. Eight distillate oil-fired boilers ranging in size from 80 BHP to 350 BHP (3.11 mmBtu/hr to 13.66 mmBtu/hr heat input). Each boiler to be equipped with oil flow monitoring instrumentation and a separate discharge stack.

The boilers will be housed in five new boiler annex buildings, each with an oil storage tank. The annex buildings will be located in close proximity to the following existing facilities:

222 - S / 2716 - S
234 - 5Z
272 - W / 2707 - W / 277 - W
283 - W / B-604
Hills Construction Complex

The 234 - 5Z annex will house three 350 BHP boilers. This will represent approximately 53% of the total 200 West Area steam generating capacity.

200 East Area. Seven distillate oil-fired boilers ranging in size from 80 BHP to 700 BHP (3.11 mmBtu/hr to 26.3 mmBtu/hr heat input). Each boiler will be equipped with oil flow monitoring instrumentation and a separate discharge stack.

The boilers will be housed in four new boiler annex buildings, each with an oil storage tank. The annex buildings will be in close proximity to the following existing facilities:

225 - B
242 - A
2707 - E / 275 - E / 2715 - EC
283 - E / B - 604

One portable boiler will operate in this area and be housed near the East/West Tank Farm.

The 242 - A annex will house one 200 BHP and two 700 BHP boilers. This will represent approximately 74% of the total 200 East Area steam generating capacity.

300 Area. Twenty-six natural gas-fired boilers ranging is size from 10 BHP to 300 BHP (0.41 mmBtu/hr to 12.25 mmBtu heat input). Each boiler will be equipped with a gas meter and a separate discharge stack.

The boilers will be housed in seventeen new boiler annex buildings in close proximity to the following existing facilities:

305
306 - E
318
320
323 / 3760
324
325
326
327
328
331
337 / 337 - B
382 / 382 B / 382 C / 382 D
3705
3709 - A
3717 / 3717 - B / 3706
3720

A small (10 BHP) boiler will be housed within the 3745 Building. Two 100 BHP boilers will be housed in the mechanical room of the 329 Building.

The 324 and 331 annex buildings will each house two 300 BHP boilers. The total from each will represent approximately 19% of the 300 Area steam generating capacity.

Central Control Center. The central control center will be located in the 300 Area. Operations of all the boilers will be monitored and controlled based on information received from the facilities in all three areas.

Boiler Shutdowns. The following boilers will be permanently decommissioned as part of a previous agreement between DOE/RL and Ecology (Agreed Order DE 96NM-087):

100 N Area	Boiler #1	Foster Wheeler
	Boiler #2	Combustion Engineering
	Boiler #3	Combustion Engineering
200 West	Boiler #1	Erie City
	Boiler #2	Erie City
	Boiler #3	Erie City
	Boiler #4	Erie City
200 East	Boiler #6	Trane

300 Area	Boiler #1	Nationwide
	Boiler #3	International
	Boiler #4	International
	Boiler #5	International

The following boilers are currently operational and will be permanently decommissioned following completion of the new boiler installations:

200 West	Babcock & Wilcox package boiler	
200 East	Boiler #1	Erie City
	Boiler #2	Erie City
	Boiler #3	Erie City
	Boiler #4	Riley
	Boiler #5	Riley
300 Area	Boiler #2	Riley
	Boiler #6	Riley

The six Wickes boilers located in the 100 KE and 100 KW Areas have been out of service since prior to 1986 and are therefore not considered in this NOC.

SECTION 2.0

BACKGROUND INFORMATION

2.1 HANFORD SITE

The Hanford Site is located in the southeastern portion of Washington State just north of the city of Richland (see Figure 2-1). The facilities occupy approximately 560 square miles.

The site was originally constructed and operated by the U.S. Army Corps of Engineers during World War II to supply nuclear materials for the Manhattan Project. The facilities have since been operated by the AEC and it successors, ERDA and DOE/RL for the production of nuclear materials and electric power, nuclear materials research, and waste management and research activities.

Three areas of the Hanford Site are directly involved in the proposed project: the 200 East and West, and the 300 Areas. (This includes the boilers which were recently shutdown under an agreement with Ecology.) Boilers in the 100 N Area were shutdown within the last 10 years and so are considered in these analyses. The shutdown of the 100 KE and 100 KW Area boilers occurred several years prior and are therefore not of concern.

The 200 Areas (East and West) are located near the center of the site and are isolated from other areas of the facility. The two areas are separated by approximately five miles.

In the past, heavy industrial activities in the 200 Areas used steam to support production, for building heating, to power turbine driven equipment, to propel waste materials through pipes, for steam cleaning of equipment, and for backup safety systems. Steam use is now limited to space heating, process needs, and safety systems. Demand is expected to continue to decline.

The 300 Area is located on the Columbia River close to the city of Richland. Steam is currently used for space heating, process steam, and hot water. Many of the buildings and production facilities in the area are scheduled for closure.

2.2 EXISTING BOILER DESCRIPTIONS

Table 2-1 presents a summary of the boilers that have operated at the Hanford Site during the last ten years. The following sections describe their design and operating histories.

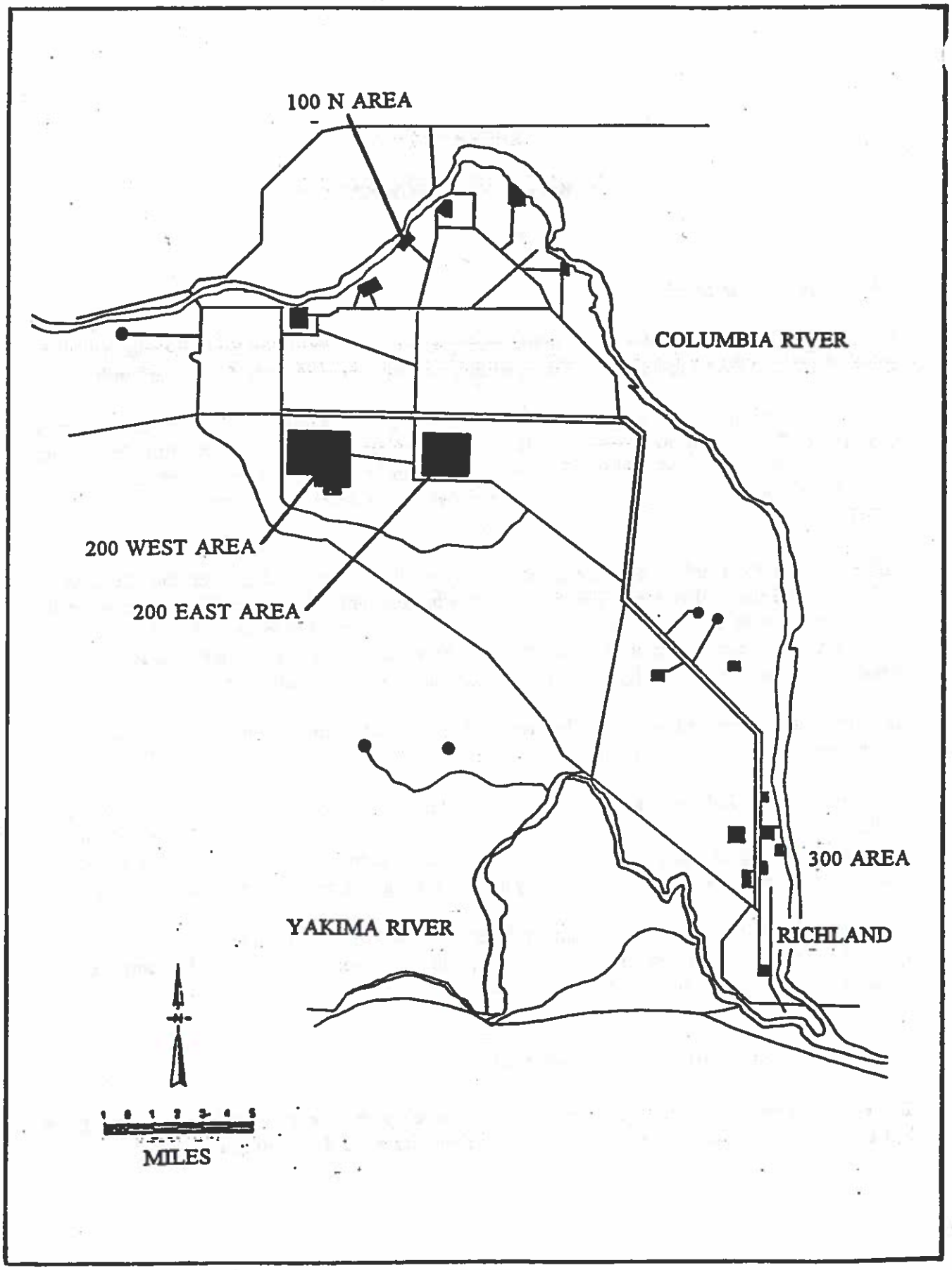
100 N AREA
COLUMBIA RIVER
200 WEST AREA
200 EAST AREA
300 AREA
YAKIMA RIVER
RICHLAND
MILES

FIGURE 2-1

TABLE 2-1
HANFORD SITE BOILER DESCRIPTIONS (August 1996)

Area/Boiler Number	Emission Point Number	Manufcturer	Operational Years		Fuels			Emission Controls	Rated Heat Input (mmBtu/h)	Steam Conditions	
			Start	End	Startup	Change	Year			Flow (klb/hr)	Press (psi)
100 N											
#1	1	Foster Wheeler	1961	1990	#6 Oil	None	- - -			500	600
#2 and #3	2	Combustion Engineering	1962-1964	1990	#6 Oil	None	- - -			200-250 (each)	- - -
200 East											
#1 to #3	11	Erie City	1944	#3-1994	Coal	None	- - -	Baghouse	102 (each)	80 (each)	225
#4 and #5	11 (also)	Riley	1954	- - -	Coal	None	- - -	Baghouse	102 (each)	80 (each)	225
#6	18	Trane	1984	1989	#2 Oil	None	- - -	0.5% S	112.5	75	- - -
200 West											
#1 to #3	12	Erie City	1944	1995	Coal	None	- - -	Baghouse	102 (each)	80 (each)	225
#4	12 (also)	Erie City	1948	1995	Coal	None	- - -	Baghouse	102	80	225
	21	Babcock & Wilcox	1995	- - -	#2 Oil	None	- - -	BACT + 0.05% S	64	50	225
300											
#1	19	Nationwide	1989	1996	#6 Oil	- - -	- - -		84	- - -	95
#2	4	Riley	1971	- - -	#6 Oil	#2 Oil	(see text)		140	100	150
#3 to #5	5, 6 + 7	International	1985	#3-1994 1989	Coal	None	- - -		56 (each)	40 (each)	150
#6	8	Riley	1958	- - -	Coal	#6 Oil	(see text)		102	80	150

2.2.1 100 N Area Steam Plant

The 100 N Area is located on the Columbia River in the northern portion of the site. Steam was used to support a nuclear reactor and supply backup electric power until the 100 N Reactor's shutdown in 1990. The 100 N boilers are located in the 184 N Building.

Three boilers were used. The No. 1 Boiler is a Foster Wheeler unit with a steam generating capacity of 500,000 lb/hr at 600 psig using No. 6 residual oil as a fuel. No. 2 distillate oil was used for startup. This boiler, the largest on the Hanford Site, was installed in 1961, completely refurbished in 1985, and removed from service in 1990.

Two identical Combustion Engineering Boilers are located in the 184 N Building Annex. The boilers are also relatively large, each having a capacity of 250,000 lb/hr using No. 6 residual oil as fuel. No. 2 oil distillate oil was used for startup. Operations of these boilers were also discontinued in 1990.

2.2.2 200 Area Steam Plants

The 200 Area steam plants are located in the 284W and 284E buildings in the 200 West and East Areas, respectively. At the time of their construction in 1944, the two boiler houses were identical. Each boiler house was equipped with three Erie City boilers (Boilers Nos. 1, 2 and 3 in each plant) firing coal, each with a rated capacity of 80,000 lb/hr steam flow.

Other boilers were added or removed from the two plants as the steam demands of the individual areas changed. The two plants operated independently until 1989 when a cross-site tie line was installed. This change allowed either plant to supply the entire demand of both areas.

Two coal-fired Riley boilers (Nos. 4 and 5) were added to the 200 East boiler house in 1954. The boilers fired coal and were of similar size as the three existing Erie City boilers. A common baghouse system for the five boilers was added in 1980 and remains operational. All five boilers remained in service through 1994 when the No. 3 Erie city boiler was shutdown for repairs. The boiler has not been operated since. The four other coal fired boilers remain operational. Due to the common discharge system, the five coal-fired 200 East boilers are grouped together for emission inventories and considered as one emitting source.

A backup package boiler (No. 6) manufactured by the Trane Company was added to the 200 East Area in 1984. The boiler fired No. 2 distillate oil until it was removed from service in 1989.

Changes were also made in the 200 West Area. An additional Erie City boiler (No.4) was added in 1948 and a Riley boiler in 1952. Both boilers fired coal and had a capacity of 80,000 lb/hr, similar to that of the original three Erie City boilers. The Riley boiler did not remain in the 200 West Area, however, and was soon moved to the 300 Area where it is now operates as Boiler No. 6. A common baghouse system was added in 1980 serving the four coal-fired boilers. Reduced steam demands in the 200 West Area and the availability of the cross-site tie resulted in the closure of the 200 West Steam Plant in 1995.

A new package boiler was installed in the 200 West Area in 1995. The boiler is equipped with BACT for NO_X control and burns very low sulfur (0.05%) distillate fuel oil. Operating hours are limited by its permit.

Only the four coal-fired boilers (Erie City Boilers Nos. 1 and 2 and Riley Boilers Nos. 4 and 5) in the 200 East Area and the Babcock & Wilcox package boiler in the 200 West Area remain in service.

2.2.3 300 Area Steam Plant

The 300 Area steam plant was built in 1944 and originally equipped with two Edgemoor coal-fired boilers. The boilers have been removed and replaced.

As mentioned above, a Riley boiler was moved from the 200 West Area to the 300 Area in 1958. The boiler (designated as No. 6) was converted from coal to oil-firing in 1971. A second oil-fired Riley boiler (designated as No. 2) was installed at that time. The latter replaced one of the original Edgemoor boilers. Both boilers initially used residual fuel oil but were switched to No. 2 diesel in 1972 and back to residual oil prior to October, 1979.

Three coal-fired boilers were installed between 1949 and 1965. One was manufactured by Babcock & Wilcox, the other two by Riley. These three boilers were removed in 1985 and replaced with three coal-fired boilers built by International. These boilers (designated as Nos. 3, 4 and 5) were used until 1989. Only one of the three (No. 3) has been operated since and that was for test burns in April and June of 1994.

The other original Edgemoor boiler (No. 1) was replaced by an Erie City coal-fired boiler in 1964 and subsequently with an oil-fired package boiler manufactured by Nationwide in 1989. The Nationwide boiler is designated as Boiler No. 1. The boiler fired residual oil and operated until January 1996 when it was removed from service.

Only the two oil-fired Riley boilers remain in service in the 300 Area.

2.3 CURRENT EMISSION INVENTORIES

2.3.1 Annual Emission Rates

Annual emission inventories for the boilers are available from 1986 to the present. A summary of the site-wide annual emission rates for the seven criteria pollutants is presented in Table 2-2. Included in Appendix A are breakdowns of the annual emissions by individual boilers or groupings of boilers. (The DOE/RL emission inventories are contained in a separate binder provided to Ecology.)

The steady decrease in steam use and fuel consumption have resulted in a steady decline in all pollutants. In the most recent calendar year (1995), the emissions of NO_X was 277 tons/year representing a decline of more than 70% from the emission inventory of 1986. Similarly, SO_2 annual emissions from the Hanford Site have decreased by over 75% in ten years.

The declines in combustible emissions (CO, PM_{10} and Total PM) have also been dramatic, representing an overall 70% reduction in these pollutants.

2.3.2 Monthly Emission Rates

Monthly emission inventories are also available. For purposes of these analyses, the monthly inventories for July 1994 through June 1996 for NO_X and CO have been grouped into quarters and are reported in Appendix C. These represent the most recent emissions data for these pollutants as compiled over the the last 24 months. The data for calendar year 1996 should be considered as preliminary as they have not been validated.

2.4 COMPLIANCE WITH REQUIREMENTS

2.1.4 Ambient Air Quality

The Hanford Site is located in an area that is attainment for all criteria pollutants.

Analyses of the impacts of the proposed changes on ambient air quality for the criteria pollutants were not requested by Ecology as part of the NOC.

2.4.2 Previous PSD Reviews

The Hanford Site is considered as a major source for purposes of PSD reviews.

SECTION 3.0

PLANNED NEW BOILER INSTALLATIONS

3.1 BOILER DESCRIPTIONS

Presented in Table 3-1 is a listing of the boilers planned for installation at the Hanford Site. Forty-one boilers are to be installed ranging in size from 10 BHP to 700 BHP. The corresponding range in heat input rate (corrected for the changes in boiler efficiency with capacity and fuel type) is 0.41 mmBtu/hr to 26.3 mmBtu/hr. It is expected that the boilers will be of a conventional "firetube" configuration similar to that shown in Figure 3-1. Other boiler arrangements are under consideration.

As indicated in Table 3-1, the sophistication of the firetube boilers' combustion controls and the available turndown increase with increasing boiler size. The smaller boilers (below 20 BHP) operate at one firing rate, that is, in either the full on or totally off firing position. There is no turndown capability on these boilers. Intermediate sized boilers (up to and including 80 BHP) operate at two firing level (low and high) which allows only limited steam generation modulation. Boilers with capacities in excess of 80 BHP will have full modulating capabilities and operate from 1/4 or 1/8 capacity up to full load depending on the fuel type.

3.2 FIRING EQUIPMENT

All boilers will be equipped with a single burner firing either natural gas or distillate oil. (Dual fuel firing capability will not be available.) The larger burners (with firing rates equal to or greater than 5 mmBtu/hr) will be equipped with low-NO_X burners with FGR (see the NO_X BACT Analysis in Section 5).

The burners on the smaller boilers (less than 5 mmBtu/hr heat input) will be standard designs that operate using good combustion practices.

3.3 FUELS

The boilers operating in the 300 Area will fire natural gas. Boilers operating in the 200 Areas will burn distillate fuel oil. None of the boilers will have dual-fuel firing capability.

TABLE 3-1
PLANNED BOILER ADDITIONS

Fuel	Size (BHP)	Operating Pressure (psig)	Total	Firing Control	Turn down	Heat Input (mmBtu/hr)	Thermal Efficiency (%)
Natural Gas	10	15	2	on-off	1:1	0.41	81
	15	15	1	on-off	1:1	0.62	81
	30	15	2	lo-hi-lo	3:1	1.24	81
	40	15	1	lo-hi-lo	3:1	1.65	81
	50	15	1	lo-hi-lo	3:1	2.07	81
	60	15	2	lo-hi-lo	3:1	2.50	81
	80	15	1	full mod	4:1	3.27	82
	100	15	6	full mod	4:1	3.97	84
	125	15	3	full mod	4:1	5.03	83
	150	15	1	full mod	4:1	5.96	84
	200	15 to 100*	2	full mod	4:1	7.89	85
	300	50 to 100*	4	full mod	8:1	12.25	82
		Total	26				
No. 2 Fuel Oil	80	15	2	full mod	4:1	3.11	86
	150	15 to 100*	2	full mod	4:1	5.74	87
	200	15 to 100*	5	full mod	4:1	7.59	86
	250	15 to 100*	1	full mod	8:1	9.51	88
	350	60	3	full mod	8:1	13.66	86
	700	15	2	full mod	8:1	26.30	89
		Total	15				

* Depending on the steam use requirements

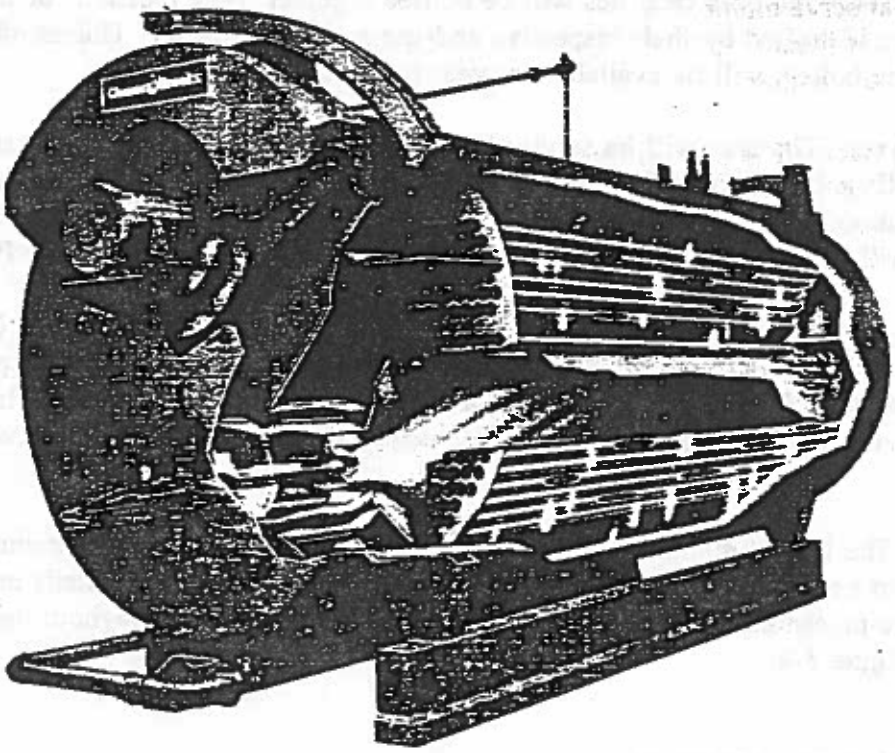

FIGURE 3-1 FIRETUBE BOILER

The distillate fuel oil used will be that commercially available in the Richland area. A typical analysis of this oil is presented in Appendix E. Of interest are the fuel oil's sulfur, nitrogen and ash contents as they directly affect SO_2, NO_X and particulate emissions. The maximum sulfur content of the oil will be limited to 0.05% (500 ppm by weight). The oil's nitrogen content is less certain but is expected to range from 0.001 % to 0.04 % (10 ppm to 400 ppm by weight). The fuel oil will also be low ash. The maximum ash content will be 0.01% (by weight).

3.4 LOCATIONS AND OPERATIONS

Most of the new boilers will be housed in new annex buildings. In some cases multiple boilers that serve multiple facilities will be housed together. The locations of the new annex buildings are identified by their respective end-use service buildings. Unless otherwise indicated, the boilers will be available for year round operation.

200 West Area. The area will be serviced by eight distillate oil-fired boilers ranging in size from 80 BHP to 350 BHP. The boilers and associated facilities are identified in Table 3-2. The distribution of the boilers in the area is shown in Figure 3-2. The largest concentration of boilers will be the three 350 BHP units serving the 234-5Z Building in the PFP Complex.

200 East Area. Seven distillate oil-fired boilers are to be installed in this area (see Table 3-2). These include the two largest boilers (700 BHP each) associated with this project. The general locations of the boilers in the area are shown in Figure 3-3. The two large boilers will service the steam demands of the 242-A evaporator and be housed along with a 200 BHP boiler.

300 Area. The largest number of boilers will be in this area. Twenty-six natural gas-fired boilers are to be installed ranging in size from 10 BHP to 300 BHP. Details on the boiler locations are presented in Table 3-3. The boilers will be located throughout the 300 Area as shown in Figure 3-4.

3.5 POTENTIAL TO EMIT

Estimates of the potential to emit have been made for each boiler based on maximum continuous operations (8760 hours per year) at full load using the emission factors presented in Table 3-4. A breakdown of each pollutant by area is presented in Table 3-5. The calculated annual criteria pollutant emission rates from each individual boiler are given in Appendix B.

Emission factors are based on guaranteed emission rates provided by the boiler manufacturer (Appendix F) and a review of information developed by the EPA (AP-42), CARB and other regulatory agencies. The emission factors used are presented in Table 3-4.

TABLE 3-2
BOILER LOCATIONS IN THE 200 AREAS

Fuel	Area	Size (BHP)	Building Location	Number Needed
No. 2 Fuel Oil	200 West	80	Hills Construction Complex	1
		200	283-W / B-604	1
		200	222-S / 2716-S	2
		250	272-W / 2707-W / 277-W	1
		350	234-5Z	3
No. 2 Fuel Oil	200 East	80	2707-E / 275-E / 2715-EC	1
		150	East/West Tank Farm*	1
		150	225-B	1
		200	283-E / B-604	1
		200	242-A	1
		700	242-A	2

* Portable boiler

TABLE 3-3
BOILER LOCATIONS IN THE 300 AREA

Fuel	Size (BHP)	Building Location	Number Needed
Natural Gas	10	3709-A	1
	10	3745*	1
	15	3705	1
	30	318	1
	30	328	1
	40	305	1
	50	323 / 3760	1
	60	337 / 337-B	2
	80	3717 / 3717-B / 3706	1
	100	326	2
	100	325	2
	100	329*	2
	125	3720	1
	125	320	2
	150	306-E	1
	200	382 / 382B / 382C / 382D	1
	200	327	1
	300	324	2
	300	331	2

* To be housed within steam use building

TABLE 2-2
HANFORD SITE BOILERS
ANNUAL CRITERIA POLLUTANT EMISSION INVENTORIES
(t/y)

Year	NO_X	SO_2	CO	PM_{10}	Total PM	Ozone (VOC's)	Lead
1986	934	2341	294	54	68	4	0.8
1987	726	1588	249	19	27	3	0.6
1988	888	1996	300	17	31	4	0.7
1989	560	1380	178	30	38	2	0.5
1990	426	1070	134	25	31	2	0.4
1991	392	977	124	22	28	2	0.3
1992	361	872	116	18	23	1	0.3
1993	400	775	128	21	26	2	0.3
1994	343	697	110	17	22	1	0.3
1995	277	544	87	16	20	1	0.2

It is understood that a complete PSD Review was conducted for the Hanford Site in 1980. Administrative changes to the PSD Review were made in January of 1987. The changes did not involve the addition or deletion of emission sources or changes to the emission quantities.

The netting analyses contained in Section 4 will demonstrate that the changes in criteria pollutant emissions will not be significant. A PSD review for these changes will not be required.

2.4.3 Toxic Air Pollutants

An analysis of the ambient air quality impacts of formaldehyde emissions has been included in this document (see Section 6) as requested by Ecology. Analyses show that no significant health risk from this toxic air pollutant will result from the planned changes.

2.4.4 Visibility Impacts

All Class I areas are more than 100 km (62 miles) from the Hanford Site. Therefore, no modeling was performed and no visibility impacts to Class I areas are expected.

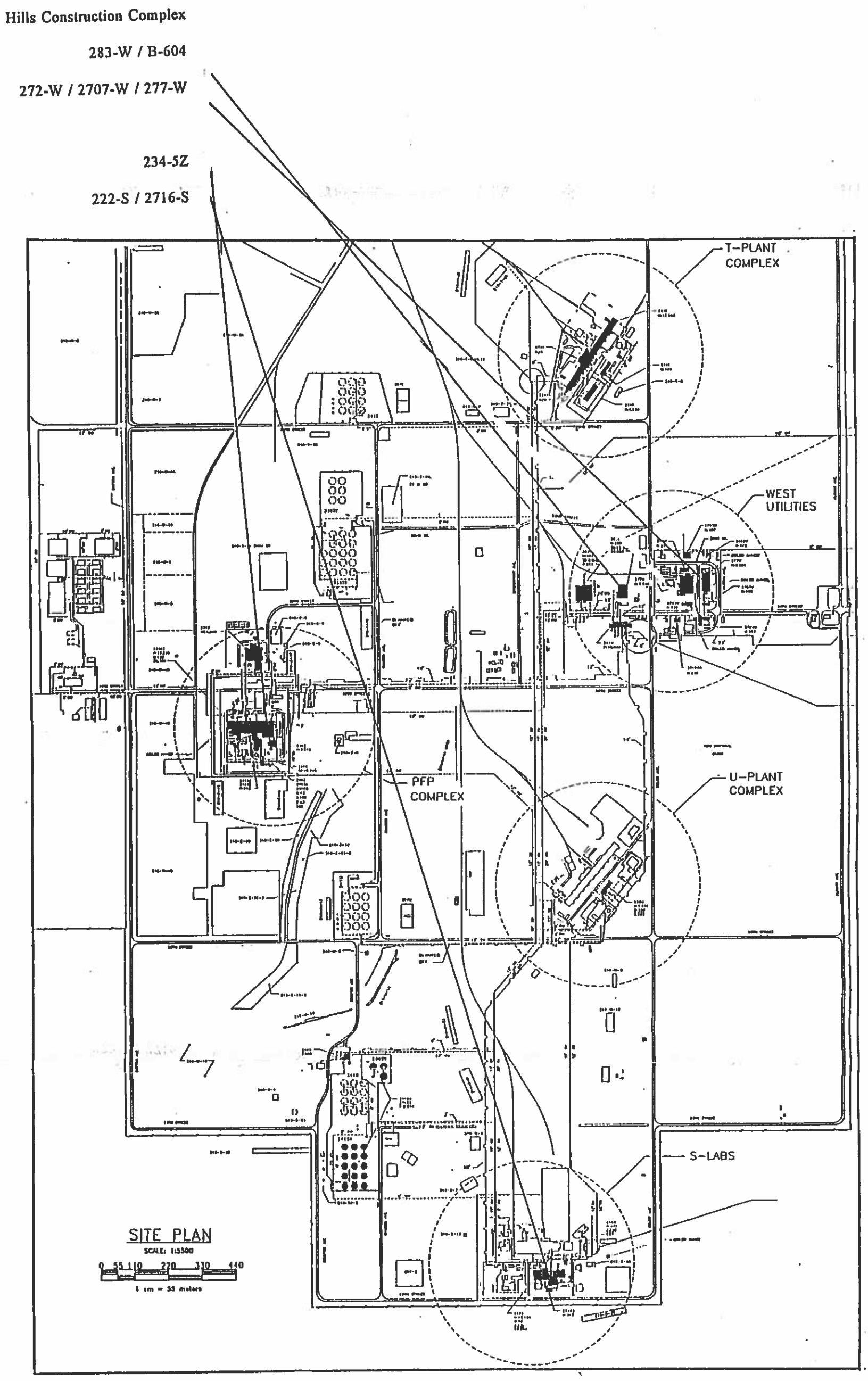
Hills Construction Complex
283-W / B-604
272-W / 2707-W / 277-W
234-5Z
222-S / 2716-S
T-PLANT COMPLEX
WEST UTILITIES
PFP COMPLEX
U-PLANT COMPLEX
S-LABS
SITE PLAN
SCALE: 1:5500
0 55 110 220 330 440
1 cm = 55 meters

FIGURE 3-2

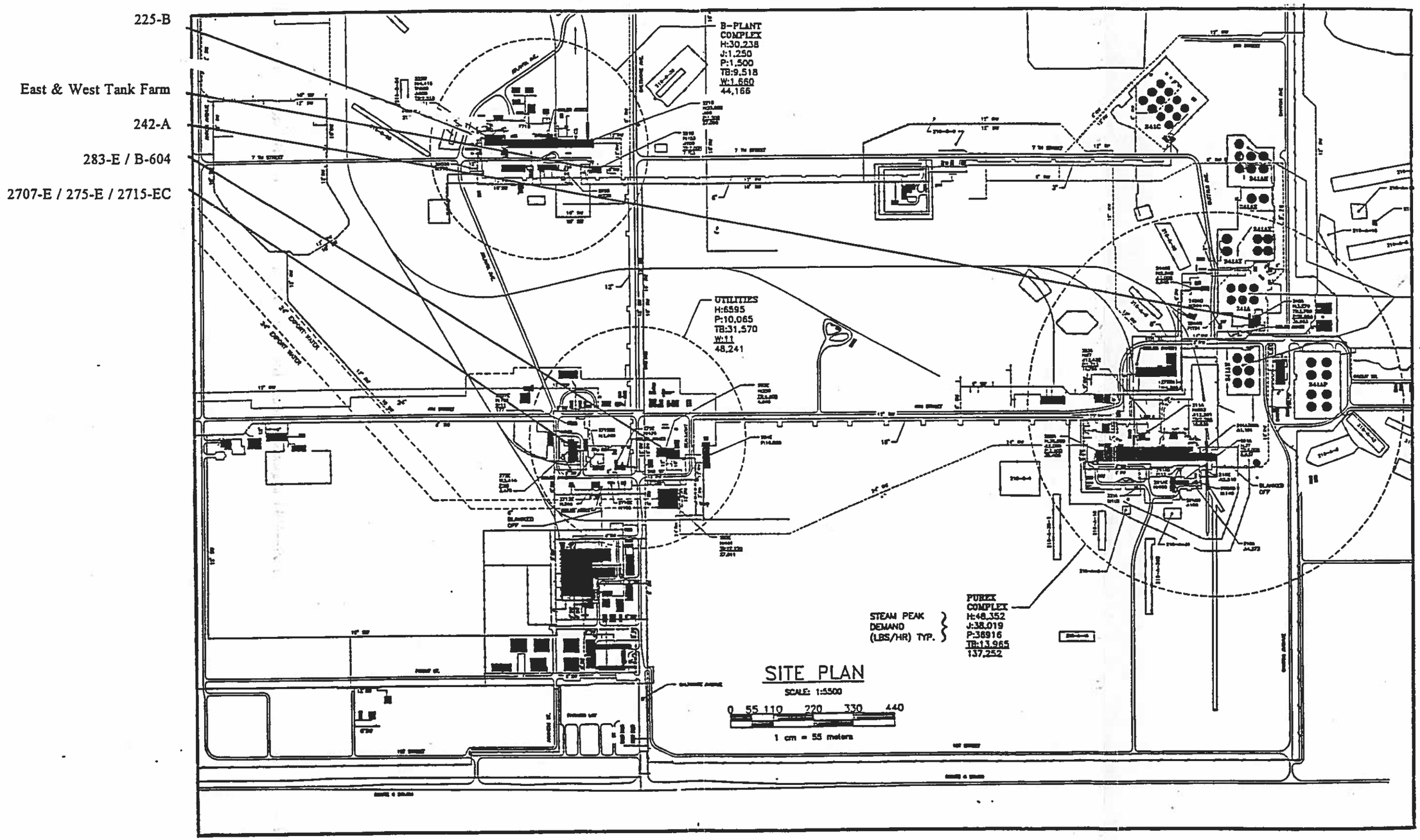
225-B
East & West Tank Farm
242-A
283-E / B-604
2707-E / 275-E / 2715-EC
B-PLANT COMPLEX
H:30,238
J:1,250
P:1,500
TB:9,518
W:1,660
44,166
UTILITIES
H:6595
P:10,065
TB:31,570
W:11
48,241
PUREX COMPLEX
H:48,352
J:38,019
P:38916
TB:13,965
137,252
STEAM PEAK DEMAND (LBS/HR) TYP.
SITE PLAN
SCALE: 1:5500
0 55 110 220 330 440
1 cm = 55 meters

FIGURE 3-3

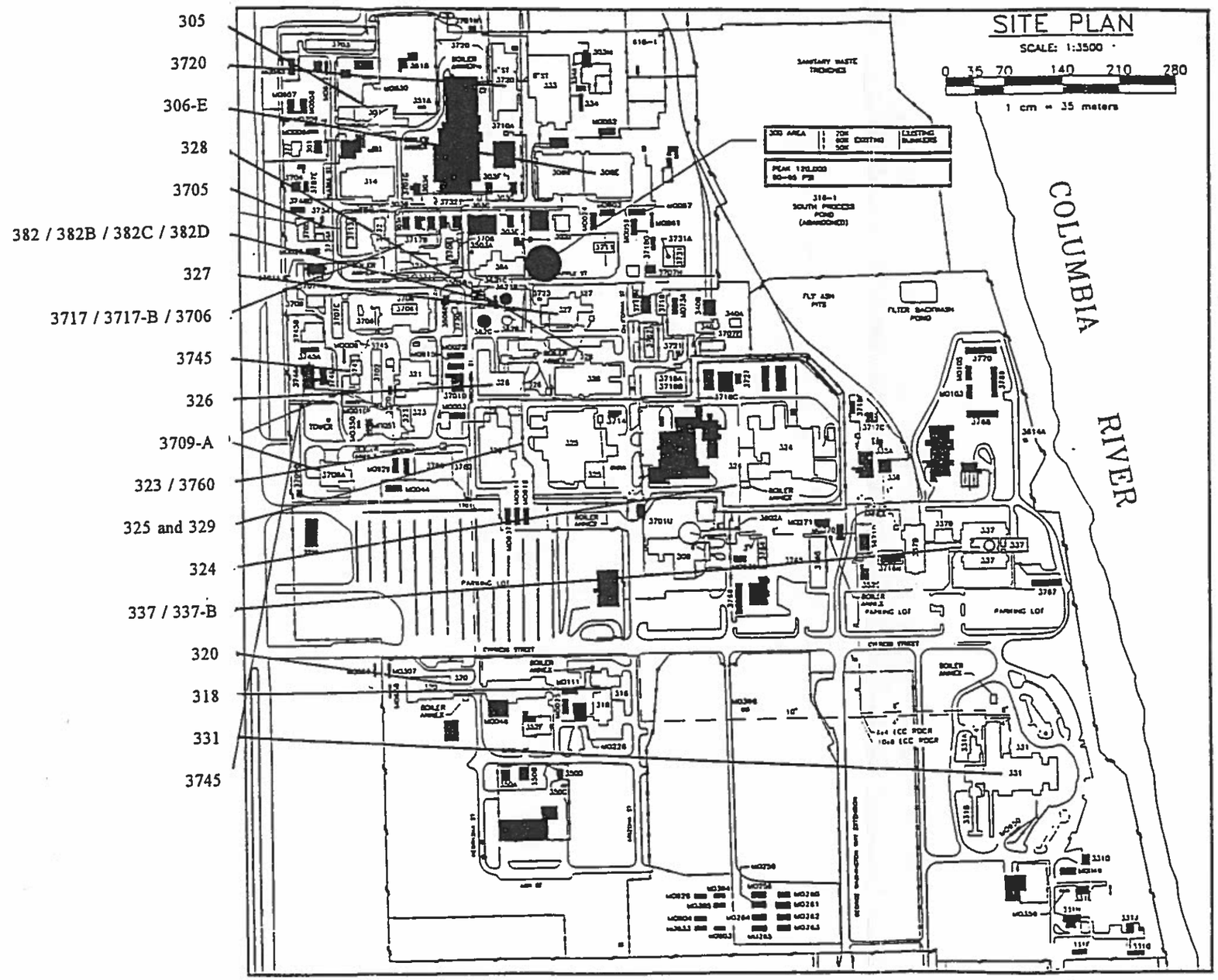
305
3720
306-E
328
3705
382 / 382B / 382C / 382D
327
3717 / 3717-B / 3706
3745
326
3709-A
323 / 3760
325 and 329
324
337 / 337-B
320
318
331
3745
SITE PLAN
SCALE: 1:3500
0 35 70 140 210 280
1 cm = 35 meters
COLUMBIA
RIVER

FIGURE 3-4

TABLE 3-4
EMISSION FACTORS USED

Pollutant	Fuel	Size Range (BHP)	Emission Factor (lb/mmBtu)	Referenced AP-42 Table	Comments
NO_X	Gas	< 125	0.100	1.4-2	85 ppm @ 3% O_2
		125 +	0.037	1.4-2	LNB w/FGR (30 ppm @ 3% O_2)
	Oil	< 150	0.180	1.3-2	140 ppm @ 3% O_2
		150 +	0.150	1.3-2	LNB w/FGR (115 ppm @ 3% O_2)
SO_2	Gas	All	0.006	1.4-2	Accepted
	Oil	All	0.051	1.3-2	0.05% sulfur distillate oil
CO	Gas	All	0.225	1.4-2	300 ppm @ 3% O_2
	Oil	All	0.071	1.3-2	90 ppm @ 3% O_2
PM_{10}	Gas	All	0.012	1.4-1	
	Oil	All	0.011	1.3-7	The boiler manufacturer considers all PM as less than 10μ
Total PM	Gas	All	0.012	1.4-1	
	Oil	All	0.015	1.3-7	
VOC's (TOC)	Gas	All	0.013	1.4-3	30 ppm @ 3% O_2
	Oil	All	0.013	1.3-4	30 ppm @ 3% O_2
Lead	Gas	All	0	- - -	VCAPCD Documentation
	Oil	All	8.9×10^{-6}	1.3-11	

TABLE 3-5
NEW BOILERS' POTENTIAL TO EMIT
(t/y)

Area	NO_X	SO_2	CO	PM_{10}	Total PM	Ozone (VOC)	Lead
200 West (Distillate Oil)	50.58	17.06	23.75	3.68	5.02	4.35	0.003
200 East (Distillate Oil)	54.72	18.47	25.71	3.98	5.43	4.71	0.003
300 (Natural Gas)	31.29	0.33	123.68	6.60	6.60	7.15	0
	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -
Totals	136.59	35.85	173.14	14.26	17.04	16.20	0.006
PSD Threshold	40	40	100	15	25	40	0.6
Exceed ?	Yes	No	Yes	No	No	No	No

The emission guarantees presented in Appendix F are intended to be practical minimums based on the size and type of boilers to be used, and the available fuel quality information. It is understood that the guaranteed NO_X levels for distillate oil firing are the lowest ever made by the manufacturer for these applications.

3.5.1 Discussion of Emission Factors for Natural Gas Fired Firetube Boilers

NO_X Emissions. Sufficient FGR will be used to control NO_X emissions to 30 ppm (0.037 lb/mmBtu) on the boilers with maximum heat input rates greater than or equal to 5 mmBtu/hr. Increased levels of FGR could be considered, however, as discussed in Section 5, the net decrease in NO_X emissions would not be cost-effective. NO_X emissions on the smaller boilers will be controlled by good combustion practices to 80 ppm (0.10 lb/mmBtu). This is consistent with AP-42 uncontrolled values.

SO_2 Emissions. The sulfur content of natural gas is negligible.

CO Emissions. Control of CO emissions requires tuning the burner hardware, combustion controls, and excess air levels. Natural gas-fired boilers are normally "tuned" so that CO levels are between 200 ppm to 400 ppm. (This is supported by the CARB emission factors presented in Appendix D). This level is the basis for the 300 ppm (0.225 lb/mmBtu) manufacturer's emission guarantee given in Table 3-4.

AP-42 emission factors do not agree with these values. CO levels are listed as 21 $lb/10^6ft^3$ (30 ppm) and 15 to 37 $lb/10^6ft^3$ (20 to 50 ppm) for uncontrolled and controlled (low-NO_X) firing, respectively. These emission levels are not practical for boilers of this size and type. In addition, simultaneous control of NO_X and CO to the levels given in AP-42 would require high levels of excess air (to control CO) and FGR (to control NO_X). As discussed in Section 5, the additional capital and operating costs required for increased levels of FGR are not justified by the emission reductions.

Particulate Matter and VOC Emissions for Natural Gas-Firing. PM and VOC emissions increase as NO_X emissions decrease. Particulate matter from natural gas combustion consists of unburned combustibles (soot and hydrocarbons). The application of more stringent NO_X controls will tend to increase these emissions.

AP-42 does not provide a PM emission factor for low-NO_X natural gas-firing . An uncontrolled emission factor for total particulate matter (assumed to be all PM_{10}) is given as 12 $lb/10^6$ ft^3 (0.012 lb/mmBtu). This emission rate has been used in Table 3-4 and is guaranteed by the boiler manufacturer for the boilers with heat input rates greater than or equal to 5 mmBtu/hr at full load firing conditions. Good combustion practices will be required to maintain control of PM levels on all boilers since the application of FGR and the low firing temperatures on the smaller boilers would be expected to adversely affect these emissions.

VOC emissions (expressed as TOC's) are listed as 8.0 lb/10^6 ft^3 (0.008 lb/mmBtu). This level is not practical nor will it be achievable under low-NO_X operation. An emission level of 30 ppm (0.013 lb/mmBtu) has been guaranteed and will provide an appropriate operating margin for all boilers.

Lead Emissions. AP-42 has no data for lead emissions for natural gas combustion. Information from Ventura County APCD (see Appendix G) has been used to confirm that there are no lead emissions and that "zero" is an appropriate emission factor.

3.5.2 Discussion of Emission Factors for Distillate Oil Fired Firetube Boilers

NO_X Emissions. NO_X emissions from distillate oil-firing depend on the fuel nitrogen content and the degree of combustion staging applied (see Section 5). AP-42 does not provide an emission factor for controlled combustion conditions. The emission factor presented in Table 3-4 for the larger boilers (heat input rates greater than or equal to 5 mmBtu/hr) applies BACT (low-NO_X burners and FGR) and is guaranteed by the boiler manufacturer. This emission factor is also consistent with the information received from CARB (see appendix D).

An NO_X emission factor of 140 ppm (0.180 lb/mmBtu) has been applied to the smaller oil-fired boilers. This is higher than the uncontrolled value presented in AP-42 and reflects the available fuel conditions and the non-continuous operations of these boilers.

SO_2 Emissions. A 0.05% sulfur fuel will generate 0.051 lb/mmBtu SO_2 emissions.

CO Emissions. Application of good combustion practices generally results in CO emission levels on distillate oil firing that are below that of natural gas firing. In many cases, the boiler will "smoke" well before there is an appreciable level of CO.

Uncontrolled CO for distillate oil combustion is listed in AP-42 (Table 1.3-2) as 5 lb/10^3 gal which is the equivalent of 0.036 lb/mmBtu (approximately 45 ppm). The use of this emission factor is questionable. While it may be possible to have CO levels in this range on very large and continuously fired boilers without NO_X controls, CO levels on boilers with low-NO_X firing will be higher. (This is discussed in AP-42, however, no CO emission factor is given.) The smaller boilers would also have difficulties achieving these levels due to their "on-off" operations cooler temperatures.

The CO emission factor guaranteed by the manufacturer is 90 ppm (0.071 lb/mmBtu). This is intended to provide a practical margin for low-NO_X firing on the larger boilers. It has also been applied to the smaller boilers to account for their non-continuous operation and relatively low temperatures. The application of good combustion practices and periodic tune-ups will be required on all boilers to maintain control of CO emissions.

Particulate and VOC Emissions. Particulate emissions are highly dependent on the sulfur and ash contents of the fuel. Incomplete combustion generates carbonaceous ash (soot) that can also be significant. VOC emissions result solely from incomplete combustion.

The AP-42 PM emission factor for industrial and commercial boilers is 2 lb/1000 gal equal to 0.0143 lb/mmBtu (Tables 1.3-7 and 1.3-8). PM_{10} emissions account for 55% on commercial boilers resulting in an emission factor of 0.0079 lb/mmBtu. 50% of the total particulate on the larger industrial boilers is PM_{10} with an emission factor of 0.0071 lb/mmBtu.

Uncontrolled VOC emission factors (expressed as TOC) emission factors are 0.252 lb/10^3 gal (0.0018 lb/mmBtu) and 0.556 lb/10^3 gal (0.004 lb/mmBtu), respectively, for industrial and commercial boilers (see Table 1.3-4).

While AP-42 does not present controlled emission factors, it does mention that "... combustion modifications which reduce the combustion efficiency will most likely increase the concentrations of organic compounds ...". As with CO, it would be expected that the PM, PM_{10} and VOC emission factors will increase with low-NO_X operations. Some adjustments to the emission factor for the small, non-continuously fired boilers will also be required.

The lower the distillate oil ash content, the lower the particulate emissions. Unfortunately, efforts to locate a distillate oil fuel supply in the Richland area with exceptionally low ash levels (less than 0.01%) have been unsuccessful. The ash content quoted by all suppliers is 0.01% which is standard for low-sulfur distillate No. 2 fuel oils. This value has been used as the basis for the PM and PM_{10} emission factors.

The consequence of low-NO_X operation on the larger boilers, non-continuous firing of the smaller boilers and the oil fuel's ash content are emission factors for PM, PM_{10} and VOC's higher than those listed in AP-42.

Lead Emissions. The AP-42 emission factor for distillate oil-firing is 8.9×10^{-6} lb/mmBtu (Table 1.3-11).

3.5.3 PSD Significance

Table 3-5 includes the PSD Significance thresholds as established by the EPA and required by the CAA. These values are published in 40 CFR 52.21(b)(23).

As indicted, only the potential annual emissions for NO_X and CO exceed their respective PSD Significance Levels. As discussed in the next section, these emissions will be sufficiently off-set by the emissions reductions associated with the boilers that have been or will be decommissioned at the Hanford Site.

SECTION 4.0

EMISSIONS NETTING ANALYSES

Since the Hanford Site is a major source, a PSD review would be required for any changes that would result in a net increase in a criteria pollutant above the prescribed threshold level.

Based on the data given in Table 3-5, the potential emission levels for NO_X and CO resulting from the installation of the new boilers exceed their PSD Significance thresholds. The increase in emissions of all other criteria pollutants are below their thresholds.

Several boilers have or will be retired once the new boilers are operational. Ecology approved procedures allow the emission "credits" from these actions to apply against increases in emissions that are above the threshold levels. This process is termed "netting." A PSD review is not required if the net change in emissions is below the threshold.

4.1 NETTING PROCEDURES

Netting involves accounting for *all* appropriate increases and decreases in emissions that have or will occur over a prescribed time period. Netting procedures are outlined in the EPA's Draft New Source Review Manual. The procedures can be summarized as:

1. The proposed change must result in an emission increase (or increases) that exceed PSD thresholds. Only the pollutant(s) that exceed their threshold levels are considered in the netting process.

2. All source-wide emission increases *and* decreases that have or will occur within a "contemporaneous" time period are considered. (An exception is made for emission changes involved in previous PSD actions.)

3. Using EPA procedures, the contemporaneous period extends back five years prior to the start of construction and through the installation and startup of the changes. Ecology considers the contemporaneous time period as extending back ten years prior to the start of construction and through installation and startup of the proposed changes. This shakedown period must be completed within 180 days of the start of construction.

4. Changes must be "creditable", i.e., be federally-enforceable at the time it occurred, or have been continuously maintained and can be made federally-enforceable prior to completing the proposed change, that is, within the 180 shakedown period.

5. Emission changes are calculated as (1) the *potential to emit* for actions that increase emissions and (2) the *actual emissions* for actions that reduce emissions. Actual emissions are based on the 12-month average of the inventoried emissions over the last two operating years (or 24 months) prior to the emission reduction.

6. The net change in emissions (the summation of the increases and decreases in emissions) that occurs during the contemporaneous period determines whether or not a significant increase will occur as a result of the project. If the net change is less than the PSD Significance threshold, then a PSD review is not required based on that pollutant.

7. The netting analyses are conducted individually for each pollutant identified in #1 above.

4.2 NETTING ANALYSES FOR NO_X AND CO

Receipt and installation of the first of the new boilers is currently scheduled late spring 1997. Completion of startup and commissioning activities for these boilers is expected within the 180 shakedown period. Additional boilers will be installed subsequently over the next several months. It is expected that the startup and shakedown periods for each boiler will be completed within the 180 day period. The installation of all forty-one boilers is expected to be completed within one-year. For purposes of these analyses, the contemporaneous period will extend from the spring of 1987 to the summer of 1998.

Several changes to boilers operating on the site have occurred over the last ten years. These changes were described in Section 2.2 and are summarized in Table 4-1. Several boilers have or will be shutdown as part of the Ecology Agreed Order DE 96NM-087. This action makes these shutdowns federally enforceable, and thereby creditable for the netting calculations.

It is understood that the remaining boilers at the Hanford Site will be permanently removed from service following completion of the new boiler startups and commissioning. These actions, once made federally enforceable, will also be creditable to the netting calculations.

The creditable emission decreases described in this section are based on the actual emissions as inventoried by DOE/RL during the last two years of the boilers' operation. For the boilers removed from service before 1995, creditable emissions are the average of the last two full calendar operating years. The annual emissions data inventories for calendar years 1986 to 1995 for each boiler are presented in Appendix A.

TABLE 4-1
BOILER CHANGES DURING THE CONTEMPORANEOUS PERIOD

Year	Description of Change
1989	Installed Boiler #1 (Nationwide boiler) in the 300 Area
1989	Shutdown Boilers #4 and #5 (International boilers) in the 300 Area
1989	Ceased operations of Boiler #6 (Trane boiler) in the 200 East Area
1990	Ceased operations of Boilers #2 and #3 (Combustion Engineering boilers) in the 100 N Area
1990	Removed from service Boiler #1 (Foster Wheeler boiler) in the 100 N Area
1994	Last operated Boiler #3 (International boiler) in the 300 Area as a test of backup capability
1995	Installed Babcock &Wilcox package boiler in the 200 West Area
1995	Closed facility housing Boilers #1, #2, #3, and #4 (Erie City boilers) in the 200 West Area
1996 (January)	Removed from service Boiler #1 (Nationwide boiler) in the 300 Area
1997/1998	Install 41 new boilers in the 200 East, 200 West and 300 Areas
1997/1998	Shutdown Boilers #1, #2, and #3 (Erie City boilers), and Boilers #4 and #5 (Riley boilers) in the 200 East Area
1997/1998	Shutdown Boilers #2 and #6 (Riley boilers) in the 300 Area
1997/1998	Shutdown the Babcock &Wilcox package boiler in the 200 West Area

For those boilers retired subsequent to 1994 or that will be decommissioned as part of this project, the actual emissions are based on the average of the two twelve month periods extending from July 1994 through June 1996. The quarterly NO_X and CO data for this period are presented in Appendix C. These data have been used as the basis for the netting analyses.

4.2.1 NO_X Emissions Netting Analyses

Presented in Table 4-2 is a summary of the potential NO_X emission increases and actual emissions decreases that have occurred or will occur over the contemporaneous period. A net decrease in NO_X emissions of 169 t/y is projected with the new boiler installation based on Ecology's ten-year contemporaneous period. Based on EPA's five-year contemporaneous period, the net change in NO_X emissions is a decrease of approximately 142 t/y.

The negative net change in NO_X emissions is below the 40 t/y PSD threshold for NO_X and is, therefore, not significant. A PSD review based on NO_X will not be required.

4.2.2 CO Emissions Netting Analyses

Presented in Table 4-3 is a summary of the potential CO emission increases and actual emissions decreases that have occurred or will occur over the contemporaneous period. A net increase in CO emissions of 57 t/y is projected with the new boiler installation based on Ecology's ten-year contemporaneous period. Based on EPA's five-year contemporaneous period, the net change in CO emissions is an increase of 86 t/y.

The net increase using either contemporaneous time period is below the PSD Significant CO threshold of 100 t/y. The net change in CO emissions is therefore not significant and a PSD review based on CO will not be required.

TABLE 4-2
CONTEMPORANEOUS NO_X EMISSION CHANGE SUMMARY

Description of Change	Year	Potential Emission Increase (t/y)	Actual Emission Decrease (t/y)
Installed Boiler #1 in the 300 Area	1989	132.3	
Shutdown Boilers #4 and #5 in the 300 Area	1989		57.4
Ceased operation of Boiler #6 in the 200 East Area	1989		0.9
Ceased operation of Boilers #2 and #3 in the 100 N Area	1990		70.3
Removed from service Boiler #1 in the 100 N Area	1990		30.6
Last operated Boiler #3 in the 300 Area as a test of backup capability	1994		0.5
Installed Babcock & Wilcox package boiler in the 200 West Area	1995	6.0	
Closed facility housing Boilers #1, #2, #3, and #4 in the 200 West Area	1995		79.4
Removed from service Boiler #1 in the 300 Area	1996 (January)		22.0
Install 41 new boilers	1997/1998	136.6	
Shutdown Boilers #1, #2, #3, #4 and #5 in the 200 East Area	1997/1998		150.8
Shutdown Boilers #2 and #6 in the 300 Area	1997/1998		31.3
Shutdown Babcock &Wilcox package boiler in the 200 West Area	1997/1998		0.4
		- - - - -	- - - - -
Totals (Ecology's 10 Year Contemporaneous Period)		274.9	443.6
Net Change	168.7 t/y Decrease	- - - - -	- - - - -
Totals (EPA's 5 Year Contemporaneous Period)		142.6	284.4
Net Change	141.8 t/y Decrease		

TABLE 4-3
CONTEMPORANEOUS CO EMISSION CHANGE SUMMARY

Description of Change	Year	Potential Increased Emissions (t/y)	Actual Decreased Emissions (t/y)
Installed Boiler #1 in the 300 Area	1989	12.0	
Shutdown Boilers #4 and #5 in the 300 Area	1989		21.0
Ceased operation of Boiler #6 in the 200 East Area	1989		0.2
Ceased operation of Boilers #2 and #3 in the 100 N Area	1990		17.6
Removed from service Boiler #1 in the 100 N Area	1990		2.8
Last operated Boiler #3 in the 300 Area as a test of backup capability	1994		0.2
Installed Babcock &Wilcox package boiler in the 200 West Area	1995	1.5	
Closed facility housing Boilers #1, #2, #3, and #4 in the 200 West Area	1995		27.6
Removed from service Boiler #1 in the 300 Area	1996 (January)		2.0
Install 41 new boilers	1997/1998	173.1	
Shutdown Boilers #1, #2, #3, #4, and #5 in the 200 East Area	1997/1998		55.2
Shutdown Boilers #2 and #6 in the 300 Area	1997/1998		3.1
Shutdown Babcock & Wilcox package boiler in the 200 West Area	1997/1998		0.1
		-----	-----
Totals (Ecology's 10 Year Contemporaneous Period)		186.6	129.8
Net Change	56.8 t/y Increase	-----	-----
Totals (EPA's 5 Year Contemporaneous Period)		174.6	88.2
Net Change	86.4 t/y Increase		

SECTION 5.0

BACT DETERMINATIONS FOR NO_X and SO_2

Ecology has requested a determination of "Best Available Control Technology" (BACT) for NO_X. BACT represents the maximum degree of reduction that is achievable for a source considering technical, economic and environmental factors. In many instances, BACT has been previously established based on determinations conducted on other, similar sources. In cases where it has not been established, a BACT determination is conducted using the particular circumstances of the case.

Based on a review of both the EPA's and CARB's BACT/LEAR Clearinghouse bulletin boards, BACT has not been established for the size and type of boilers being considered.

Consequently, BACT determinations have been made using the step-wise "top-down" procedures described in EPA's New Source Review Workshop Manual. A baseline BACT level is assumed. All more effective control technologies are evaluated starting with the most effective and working down. This includes all applicable technologies. Control techniques that are not technically feasible are then eliminated. The cost of the remaining technologies is then determined. Control technologies with unacceptable cost-effectiveness levels are discarded. The technology remaining with the highest reduction performance is BACT. If all control technologies fail either the technical or economic criteria, then the baseline is BACT.

Baseline BACT (least acceptable level of control) has been taken to be:

Pollutant	Boiler Heat Input Rate	Baseline BACT
NO_X	Greater than or equal to 5 mmBtu/hr	Low-NO_X Burners with FGR
NO_X	Less than 5 mmBtu/hr	Good Combustion Practices
SO_2	All boilers	0.05% Sulfur Distillate Oil

BACT for the other criteria pollutants (CO, PM_{10}, total PM, and VOC's) has been taken to be the application of good combustion practices. This is generally accepted by regulatory agencies throughout the U.S. for boilers not subject to specific regulatory limits.

Reference is made to information obtained from CARB (see Appendix D). This document provides useful information and control cost-effectiveness data for boilers of the size and type to be installed on the Hanford Site and was the only such document identified.

5.1 AVAILABLE NO_X CONTROL TECHNOLOGIES

5.1.1 NO_X Formation and Uncontrolled NO_X Emission Levels

NO_X is formed during combustion by the oxidation of nitrogen contained in the combustion air and that bound into the fuel's organic structure. The amount of NO_X emitted depends on the concentration of reactants (oxygen and nitrogen), the reaction temperature, and the available residence time. Efforts to control NO_X emission levels involve adjusting the design or operation of the combustion process to beneficially affect one or more of these parameters.

Thermal NO_X. The NO_X formed during natural gas combustion is due entirely to high temperature reactions between the oxygen and nitrogen in the combustion air. These reactions are very sensitive to temperature and produce appreciable NO_X at temperatures in excess of 2800°F. The quantity of NO_X increases exponentially at higher temperatures. Uncontrolled NO_X levels for the boilers involved in the project are on the order of 80 ppm (0.10 lb/mmBtu). NO_X emissions can be reduced by cooling peak flame temperatures provided that flame stability and complete combustion are not adversely affected.

Distillate oil combustion also generates flame temperatures high enough to produce NO_X. The physical arrangement of the oil flame results in Thermal NO_X levels higher than on natural gas and less affected by reduced flame temperatures.

Fuel-Bound NO_X. The conversion (oxidation) of nitrogen in the fuel also forms NO_X. The trace quantities of nitrogen in the oil are released and react as the oil droplets vaporize in the "near burner" region. The nitrogen reacts with either oxygen to form NO_X or with another nitrogen atom to form molecular nitrogen (N_2). As described below, low-NO_X burners are designed to control the mixing of air into the flame and thereby limit the availability of oxygen near the burner. This has demonstrated to be the most effective control method.

The more nitrogen in the oil, the higher the NO_X emissions. Not all of the nitrogen is converted to NO_X. Based on information published by CARB, 65% of the nitrogen contained in a 0.1% nitrogen fuel oil is converted to NO_X under normal firing conditions. The proportion of nitrogen oxidized to NO_X increases with decreasing nitrogen content.

Distillate oils available on the west coast typically have fuel-bound nitrogen contents of 200 ppm to 600 ppm (0.02% to 0.06%) by weight. Information received from a fuel oil supplier in the Richland Area (Appendix E) indicates a likely range of 10 ppm to 400 ppm nitrogen in distillate fuel oil. For discussion, the fuel-bound nitrogen has been assumed to be 0.04%. Using a conversion rate of 85%, uncontrolled NO_X emissions of approximately 50 ppm (0.06 lb/mmBtu) from fuel-bound nitrogen would be expected.

Total Uncontrolled NO_X Emissions. Uncontrolled emissions from natural-gas combustion are expected to be approximately 80 ppm (0.10 lb/mmBtu). Total NO_X emissions using the fuel

oil commercially available in Richland are the sum of the Thermal and Fuel-Bound NO_X components, or approximately 140 ppm (0.180 lb/mmBtu).

5.1.2 Substitution of Low Nitrogen Fuels for Distillate Fuel Oil

One means of reducing NO_X emissions from distillate oil combustion is by substituting fuels with lower fuel nitrogen contents. Low-nitrogen distillate fuel available in Western Washington or natural gas could be considered.

Low-Nitrogen Distillate Fuel Oil. Distillate oil with a typical fuel-bound nitrogen content of 50 ppm (0.005%) by weight is produced in Tacoma (see Appendix E). Based on a 90% conversion of fuel-bound nitrogen to NO_X, uncontrolled emissions from this fuel would be approximately 6 ppm (0.008 lb/mmBtu). With low-NO_X burners and FGR, the total NO_X emissions using this oil would be approximately 80 ppm representing a 30% NO_X reduction.

The low-nitrogen fuel is currently used exclusively for transportation in Western Washington. It is not commercially available in the Richland area. It has been estimated that the cost to ship this oil to the Hanford Site would be approximately $0.10/gal ($0.71/mmBtu). Additional costs would be incurred with the need for special storage fact facilities in the Richland area to isolate this fuel from other fuel stocks. This would further raise fuel costs.

Natural Gas. Contains no fuel bound nitrogen so that the potential reduction efficiency of the NO_X formed from fuel-bound nitrogen is 100%. Emission levels firing natural gas would be comparable to the low-NO_X burners to be installed in the 300 Area. Natural gas is currently not available in the 200 Areas.

5.1.3 Combustion Control Technologies

A summary of the available combustion control technologies is presented in Table 5-1.

Low Excess Air (LEA) Operation and "Good Combustion Practices". Minimizing the availability of air (oxygen), especially in the near burner region is of fundamental importance in controlling NO_X emissions. This applies to both natural gas and distillate oil fuels.

All burners require excess air (above that theoretically required) to complete combustion. Well tuned boilers operate at "minimum" excess air, that is, having just enough air to complete combustion and maintain acceptable levels of unburned combustibles (carbon monoxide or soot). Very low excess air levels must be avoided. Excessive combustibles are considered as air pollutants and, at high enough levels, can cause explosions.

Operating at minimum excess air is an integral part of good boiler operations and is used with all other NO_X controls. Good combustion practices involves implementing LEA operation.

TABLE 5-1
COMBUSTION BASED NO_X CONTROL TECHNOLOGIES

Control Technology	Description	Advantages	Disadvantages
Fuel Substitution	Decrease the fuel oil nitrogen content	- Minimal fuel system changes	- Relatively expensive - Lowers boiler efficiency on gas fuel
Low Excess Air (LEA) using "Good Combustion Practices"	Operating at near minimum excess air	- Low cost - Peak efficiency	- Limited NO_X reduction - Requires periodic tuneups
Flue Gas Recirculation (FGR)	Mixed exhaust gases with air to reduce flame temperatures	- Effective for Thermal NO_X	- Increased capital costs - Increased operating costs - Increases boiler size
Reduced Air Temperature	Bypass part of the air around air heater	- Convenient on some units	- Limited NO_X reduction - Not applicable to firetube boilers
Staged Combustion.			
Low NO_X Burners	Controlled fuel and air mixing	- Low operating costs - Effective for Fuel NO_X	- Increased capital costs - Not used on boilers <5 mmBtu/hr
Overfire Air (OFA)	Redistribute air to flame	- Effective for Fuel NO_X	- Not applicable to firetube boilers
Burners-Out-of-Service	Redistribute fuel	- Effective for Fuel NO_X	- Not applicable to firetube boilers
Fuel Biasing	Redistribute fuel	- Convenient on some units	- Not applicable to firetube boilers
Reburning	Form secondary burning zone to reduce NO_X	- Potential for very low NO_X	- Not commercially demonstrated - Not applicable to firetube boiles

The objectives are to maintain minimum excess air levels with acceptable combustibles and assure stable combustion conditions at all times. Adequate combustion controls must be installed and maintained. Regular burner and boiler hardware maintenance must be performed including periodic combustion tuneups. Good combustion practices contribute to improved boiler economics by maximizing its thermal efficiency.

Flue Gas Recirculation (FGR). Peak combustion temperatures can be reduced by recirculating a portion of spent flue gases back into the flame. This provides a diluent that lowers flame temperatures. A secondary benefit is the dilution of the oxygen in the flame. FGR can be added to the flame on firetube boilers by either (1) adding it to the incoming combustion air through the FD fan, (2) inducing recirculating mixing patterns of furnace gases back into the flame, or (3) both.

Since the formation of NO_X during natural gas combustion is entirely Thermal NO_X, the application of FGR to this fuel has demonstrated very high reductions (60% to 70% depending on the quantities of FGR). Its effectiveness on distillate oil is much less due to the differences in flame characteristics. Reductions in Thermal NO_X formation of 10% to 20% have been demonstrated on oil. High levels of FGR during oil combustion are limited by high combustibles. FGR has negligible effects on the conversion of fuel-bound nitrogen.

FGR adds to the costs of installing and operating the boiler. Adding FGR increases gas flow and pressure drops through the boiler. Larger boiler gas passes are required. The larger pressure drops also increase FD fan horsepower consumption.

Reduced Combustion Air Temperature. Lowering the combustion air temperature reduces the energy transferred to the flame and peak combustion temperatures. A small reduction (up to 5%) on the rate of Thermal NO_X formation can be achieved. This technique is not applicable for firetube boilers since they doe not use air preheat.

Staged Combustion. As discussed above, the key parameter in controlling NO_X formation from fuel nitrogen is the near-burner air-to-fuel ratio (stoichiometry). Minimum stoichiometry levels are achieved by (1) delaying the mixing of air near the burner and providing intense mixing late in the flame to achieve complete combustion, (2) distributing the fuel input to achieve the desired stoichiometry, or (3) both. These techniques are called combustion "staging." Staging can be implemented in several ways by adjusting the arrangement of the air and fuel inputs through the burner.

It is important to understand that staged combustion was developed for large utility boilers that operate at steady firing conditions. These boilers have multiple burners and relatively large furnaces. The combustion and operating conditions and the flexibility to change air and fuel mixing patterns on these boilers are considerably different than the firetube boilers to be installed at Hanford. (Discussions of their technical feasibility for firetube boilers will follow in Section 5.2.)

Several low-NO_X burner (LNB) configurations are commercially available for use in natural gas and distillate oil fired boilers. In all cases, combustion staging is achieved by closely controlling the injection and mixing patterns of fuel and air. The effectiveness of LNB's varies greatly depending on fuel type and combustor design.

Due to the delayed mixing of air and fuel, flames produced by LNB's are longer than conventional (uncontrolled) flames. Its application firetube boilers is limited by the firebox geometry. Reductions of 10% to 15% would be expected on these boilers, well below the 25% to 35% levels demonstrated on utility boilers.

Staged combustion can also be achieved by injecting a portion of the combustion air through specially arranged air ports (termed "overfire air" or OFA) that form air jets that intersect the flame downstream of the near-burner region. Sufficient OFA jet momentum and penetration must be provided to rapidly mix the OFA into the flame. Additional residence time in the furnace is required. This technology is not available for use on firetube boilers.

Staged combustion can be implemented on multiple burner boilers by shutting down fuel flow to selected burners and redistributing it to the remaining burners. Uniform airflow to all burners is maintained. This technique is termed "burners-out-of-service" (BOOS) operation and is very effective on utility boilers. It is not applicable to firetube boilers.

Flue Biasing differs from BOOS in that all burners remain in service with nonuniform fuel distribution. In this way, the stoichiometry of individual burners can be adjusted to gain a net decrease in emissions. Fuel biasing is also not applicable to single burner boilers.

Reburning. This experimental technique involves splitting the combustion process in the furnace into multiple zones having varied stoichiometries. The NO_X formed in one area is reduced (stripped of oxygen) in a subsequent combustion zone operated at very low air levels. This approach is not applicable to firetube boiler due to the limited furnace volume.

5.1.4 Post-Combustion NO_X Control Technologies

The bulk of the NO_X released from the furnace is in the form of nitric oxide (NO). NO can be removed from the flue gases prior to exiting the boiler by reactions with ammonia (or ammonia based reagents) to form N_2 and water. These "selective" reactions occur in narrow temperature windows that vary with the application and type of reagent used.

Selective Non-Catalytic Reduction (SNCR). The reactions occur readily in the gas stream at 1500°F to 1900°F when ammonia is injected into the flue gases. The necessary conditions for applying this technology are:

An appropriate temperature window,
Rapid and complete mixing of reagent into the flue gas stream,

Sufficient residence time to complete the reduction reactions,
Adequate quantities of reagent to achieve the desired NO_X reductions, and
Minimal ammonia "slip" into the atmosphere.

Temperature and time are the key parameters. The temperatures of interest are available in the superheat section of many industrial and utility boilers. Operating with temperatures above the SNCR window produces NO_X. Operating a lower temperatures result in the release ("slip") of ammonia to the atmosphere. A residence time of approximately 0.25 seconds is needed to complete the reactions.

Performance also depends on the quantity of reagent injected. This is measured by the molar ratio of equivalent ammonia in the reagent to the NO in the gas stream (termed the "normalized stoichiometric ratio" (NSR)). An NSR of 1.0 is needed to achieve a 30% NO_X reduction. Reductions in excess of 50% require NSR's of 1.5 to 2.0. Higher NSR's result in high slip levels which is considered as an air pollutant.

Neither an appropriate temperature window nor residence time is available on firetube boilers. SNCR, therefore, cannot be applied.

Selective Catalytic Reduction (SCR). The reactions are identical to those described above but occur at lower temperatures and in the presence of a catalyst. SCR has been installed on several large boilers where the exhaust gas temperature is between 600°F and 750°F. These temperatures are not available at the exhaust of firetube boilers.

The NO_X reduction performance and the quantity of ammonia slip on other boiler designs are dependent on the NSR, the arrangement of the catalyst, and the flue gas temperature and flow conditions. Generally, removal efficiencies of 70% to 90% can be achieved.

5.2 NO_X CONTROL TECHNICAL FEASIBILITY ANALYSES

A summary of the technical feasibility evaluations is presented in Table 5-2.

5.2.1 Substitution of Low Nitrogen Fuels In Distillate Oil-Fired Boilers in the 200 Areas

Use of Low Nitrogen Distillate Fuel Oil. Fuel properties are similar to commercial fuel oils.

Determination: Technically Feasible For All Boilers

Natural Gas. Natural gas could replace the distillate oil. A small (2%) thermal efficiency penalty would be imposed which would increase fuel consumption.

Determination: Technically Feasible For All Boilers

TABLE 5-2
NO_X CONTROL TECHNICAL FEASIBILITY SUMMARY

Control Technology	Feasible For Firetube Boilers (yes/no)			NO_X Reduction (%)		Comments
	Oil	Gas	Small	Oil	Gas	
Fuel Substitution to Low Nitrogen Fuels						
Low nitrogen distillate oil	Yes	N/A	Yes	30	N/A	Not commercially available in Richland
Switch from Oil to Natural Gas	Yes	N/A	Yes	73	N/A	Not currently available to the 200 Areas
Combustion Changes						
Low-NO_X Burners with FGR	Yes	Yes	?	0	0	Baseline for BACT analyses Application to boilers less than 5 mmBtu/hr is questionable
Low-NO_X Burners with Increased FGR	No	Yes	No	0	17	Not used on oil-fired boilers due to high combustibles
Reduced Air Temperature	No	No	No	- - -	- - -	Combustion air is not preheated
Overfire Air (OFA)	No	No	No	- - -	- - -	Furnace volumes too small
Burners-Out-of-Service (BOOS)	No	No	No	- - -	- - -	Firetube boilers use only one burner
Fuel Biasing	No	No	No	- - -	- - -	Firetube boilers use only one burner
Post Combustion Technologies						
Selective Non-Catalytic Reduction (SNCR)	No	No	No	- - -	- - -	Insufficient time/temperature window
Selective Catalytic Reduction (SCR)	No	No	No	- - -	- - -	Boiler exit temperatures too low

5.2.2 Combustion Control Technologies

Low Excess Air (LEA) Operations. LEA is incorporated as part of good combustion practices on all boilers.

Determination: Technically Feasible For All Boilers

Flue Gas Recirculation (FGR). The use of FGR increase FD fan horsepower and requires larger boiler convective passes. The application of FGR on the smaller boilers (less than 5 mmBtu/hr) is questionable due to the small fireboxes and the non-continuous operations.

Determination: Technically Feasible (greater than or equal to 5 mmBtu/hr)
Questionable Feasibility (less than 5 mmBtu/hr)

Increased FGR High levels of FGR on distillate oil fired boilers is not recommended due to the adverse impacts on combustible emissions. This technology can be used on natural gas.

Determination: Technically Feasible (natural gas boilers with heat input rates greater than or equal to 5 mmBtu/hr)
Technically Infeasible (distillate oil and small boilers)

Reduced Combustion Air Temperatures. The boilers under consideration do not have air heaters so the use of this technique is inappropriate.

Determination: Technically Infeasible For All Boilers

Staged Combustion - Low-NO_X Burners (LNB). LNB have been applied to boilers with heat input rates as low as 5 mmBtu/hr. The application to smaller combustors is questionable due to limited heat input rates, restricted firebox geometry, and non-continuous operations.

Determination: Technically Feasible (greater than or equal to 5 mmBtu/hr)
Questionable Feasibility (less than 5 mmBtu/hr)

Staged Combustion - Overfire Air (OFA). Firetube boilers have restricted fireboxes.

Determination: Technically Infeasible For All Boilers

Staged Combustion - Burners-Out-of-Service (BOOS). The boilers will have only one burner.

Determination: Technically Infeasible For All Boilers

Staged Combustion - Fuel Biasing. The boilers will have only one burner.

Determination: Technically Infeasible For All Boilers

5.2.3 Post-Combustion Control Technologies

Selective Non-Catalytic Reduction (SNCR). This technology requires the flue gases to be held at a temperature of 1500°F to 1900°F for a period of 0.25 seconds. Suitable temperature window and residence period are not available on firetube boilers with modulating firing and non-continuous operations.

Determination: Technically Infeasible For All Boilers

Selective Catalytic Reduction (SCR). The exit gas temperatures from firetube boilers are 400°F to 500°F depending on the operating pressure and number of passes. These temperatures are too low for effective use of this technology.

Determination: Technically Infeasible For All Boilers

5.3 NO_X CONTROL COST-EFFECTIVENESS ANALYSES

The cost-effectiveness of a NO_X control technology is determined by dividing its cost (on an annualized basis) by the net annual NO_X reduction. Cost-effectiveness is expressed in units of "$/ton NO_X reduced." Cost-effective values in excess of $2000/t are considered as unacceptable since they would impose an unacceptable financial impact on the source.

Two cost-effectiveness values have been determined:

The **Average Cost-Effectiveness** based on the cost and NO_X reduction from the baseline condition.

The **Incremental Cost-Effectiveness** based on the differential cost and NO_X reduction of one technology to the next more effective technology.

Emission levels and operating costs are based on "realistic upper bound operating assumptions" as defined by the EPA. For purposes of these analyses, it has been assumed that the boilers will operate with an annual capacity factor of 25%. This is considered appropriate for the application.

5.3.1 NO_X Control Cost-Effectiveness For Small Boilers With Heat Input Rates Less Than 5 mmBtu/hr

Natural Gas and Distillate Oil-Fired Boilers. Since the application of low-NO_X burners and FGR has questionable technical feasibility, it is necessary to conduct a cost analysis. The costs using low nitrogen fuels on these boilers will be considered with the larger boilers.

Presented in Table 5-3 are cost-effective values for the application of a Low-NO_X burner and FGR to a boiler with a heat input rating of 3.5 mmBtu/hr (85 BHP) at various annual capacity factors. These data are taken from the referenced CARB document. These data indicate cost-effectiveness levels of $4000/t to $29,000/t depending on the annualized capacity factor. Using the 25% annual capacity factor, the cost-effectiveness is approximately $12,000/t. This value is above that considered acceptable.

Application of these technologies to boilers within the 5 mmBtu/hr size range would also be financially unacceptable. For boilers with heat input rates less than the 3.5 mmBtu/hr given in Table 5-3, the cost-effectiveness will be higher. For boilers with heat input rates greater than 3.5 mmBtu/hr up to 5 mmBtu/hr, the cost-effectiveness of these technologies would not be expected to change significantly.

Based on their high cost-effectiveness levels, the application of low-NO_X burners or FGR are not considered as BACT for boilers having heat input rates less than 5 mmBtu/hr.

5.3.2 NO_X Control Cost-Effectiveness For Larger Boilers With Heat Input Rates Greater Than or Equal to 5 mmBtu/hr

Natural Gas-Fired Boilers. Presented in Table 5-4 are the cost-effectiveness values for the application of increased FGR to a 12 mmBtu/hr (300 BHP) gas-fired boiler, the largest considered in this project. The level of FGR is higher than that provided in the manufacturer's guarantee and is intended to achieve 70% NO_X reduction.

The costs associated with the use of increased levels of FGR has been taken from manufacturer supplied information. For the 300 BHP boiler, the increased capital costs for the larger firebox and FD fan are estimated to be $2000. Using an annualizing factor of 0.16, the annualized cost for this capital expenditure is $2000 x 0.16 = $320. Assuming that the fan consumes an additional 5 hp/hr at an electric power cost of $0.03/kw-hr and operates year round at 25% capacity, the annual operating cost increase is 5 x $0.03 x 8760 x 0.25 = $330. The total annualized capital and operating cost is $320 + $330 = $650/yr. These values are presented in the table.

The associated reduction in NO_X is determined by multiplying the potential annual emission reductions by the capacity factor. The projected reduction is 0.07 t/y. The average cost-effectiveness of this technology would therefore be $650/yr divided by 0.07 t/y = $9300/t.

Several natural gas-fired boilers with lower heat input rates are to be installed in the 300 Area. Application of increased FGR to these boilers will result in a higher cost-effectiveness value.

No incremental cost-effectiveness analysis is needed as there are no other technically feasible and more effective NO_X control option to consider.

TABLE 5-3

COST-EFFECTIVENESS OF NO_X EMISSION CONTROL TECHNOLOGIES BOILERS WITH HEAT INPUT RATES OF 3.5 MMBTU/HR

Control Technology	Annual Capacity Factor (%)	Cost-Effectiveness (1000$/t)
Low-NO_X Burners	10	27.0
	50	6.4
	90	4.0
Flue Gas Recirculation	10	29.0
	50	6.8
	90	4.0

Reference: Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial , Institutional, and Commercial Boilers, Steam Generators, and Process Heaters" State of California Air Resources Board, Criteria Pollutants Branch, Stationary Source Division, July 18, 1991.

TABLE 5-4
TOP-DOWN BACT IMPACT ANALYSIS FOR NO_X
NATURAL GAS-FIRED BOILER WITH 12.3 MMBTU/HR HEAT INPUT
(300 BHP)

Control Technology	NO_X Emissions			Economic Impacts				Detrimental Impacts (yes/no)	
	Target (ppm)	Annual[1] (t/y)	Reduction (t/y)	Capital Costs ($1000)	Annualized Costs[2] ($1000/y)	Average Cost Effectiveness ($1000/t)	Incremental Cost Effectiveness ($1000/t)	Energy	Environ-mental
LNB w/Increased FGR	25	0.40	0.08	2.0	0.65[3]	8.1	- - -	Yes	Yes
Baseline LNB w/FGR	30	0.48	- - -	- - -	- - -	- - -	- - -	- - -	- - -

1. Based on a 25% capacity factor
2. 0.16 capitalization factor
3. Includes increased FD fan horsepower costs = 5 hp/hr x 1 kw-hr/hp x 8760 hr/yr x 0.25 x $0.03/kw-hr = $330/yr

The application of this control technology for natural gas-fired boilers with heat input rates in the range of 5 to 12 mmBtu/hr will have cost-effectiveness values well above accepted levels ($2000/t). The use of increased FGR would also increase combustible emissions. Increased FGR is, therefore, not considered as BACT.

Distillate Oil-Fired Boilers. Presented in Table 5-5 are the cost-effectiveness values for the application of low-nitrogen fuels (distillate oil and natural gas) on a 26.3 mmBtu/hr (700 BHP) oil-fired boiler. This is the largest boiler size to be installed.

Using the low-nitrogen distillate oil is estimated to reduce NO_X to approximately 80 ppm. Excluding the costs for new storage facility in Richland, the higher transportation cost will increase the price by approximately $0.10/gal ($0.71/mmBtu). Based on the analysis given in Table 5-5, the average cost-effectiveness of this approach would be on the order of $32,500/t.

Substituting natural gas would lower NO_X to 30 ppm. Using natural gas in the boilers designated for distillate oil-firing would require extending the natural gas pipeline from the 300 Area to the 200 Area. The cost to install the pipeline would be several million dollars. For this analysis, it has been assumed that the total cost would be $5 million. Each of the 700 BHP boilers in the 200 East Area will consume approximately 16% of the total gas transferred. Proportioning the costs of the pipeline by fuel use results in a capital allocation to each boiler of approximately $800,000. The average cost-effectiveness for this approach would be $42,000/t as shown in Table 5-5.

The use of increased levels of FGR and fuel switching have very high cost-effectiveness values and will result in increased energy consumption and may increase the release of other air pollutants. Their application is not BACT.

5.4 DETERMINATION OF BACT FOR NO_X

Since the application of all other more effective control technologies than the assumed baseline BACT technology on these boilers has been shown to be inconsistent with BACT, their use will not be considered.

BACT for boilers with heat input ratings greater than or equal to 5 mmBtu/hr will be low-NO burners equipped with FGR.

For the smaller boilers, BACT will be taken to be conventional burners operated with good combustion practices.

TABLE 5-5
TOP-DOWN BACT IMPACT ANALYSIS FOR NO_X
DISTILLATE OIL-FIRED BOILER WITH 26.3 MMBTU/HR HEAT INPUT
(700 BHP)

Control Technology	NO_X Emissions			Economic Impacts				Detrimental Impacts (yes/no)	
	Target (ppm)	Annual[1] (t/y)	Reduction (t/y)	Capital Costs ($1000)	Annualized Costs[2] ($1000/y)	Average Cost Effectiveness ($1000/t)	Incremental Cost Effectiveness ($1000/t)	Energy	Environ-mental
Natural Gas	30	1.07	3.05	800[3]	128[4]	42.0	N/A[6]	Yes	No
Low Nitrogen Oil	80	2.86	1.26	0	40.9[5]	32.5	- - -	No	No
Baseline LNB w/FGR	115	4.12	- - -	- - -	- - -	- - -	- - -	- - -	- - -

1. Based on a 25% capacity factor
2. 0.16 capitalization factor
3. Proportional cost of a $5 million natural gas pipeline from Richland to the 200 Areas
4. Does not include a fuel cost differential
5. Fuel transportation costs only = $0.71/mmBtu x 26.3 mmBtu/hr x 0.25 x 8760 hrs/yr = $40,900
6. Natural gas and distillate oil use cannot be combined

5.5 AVAILABLE SO_2 CONTROL TECHNOLOGIES

5.5.1 SO_2 Formation

The sulfur contained in the fuel oil is oxidized completely during combustion to form sulfur dioxide (SO_2). Depending on combustion conditions, a portion of the SO_2 may be further oxidized to sulfur trioxide (SO_3). High excess air, relatively low combustion temperatures, and long residence times in the combustion chamber promote the oxidation of SO_2 to SO_3. High SO_3 levels are characteristically observed at low load operations.

Under normal circumstances, the sulfur oxides exist as a vapor and exit the boiler with the flue gases. As temperatures decrease, the SO_3 in the flue gases combines with water vapor to form sulfuric acid (H_2SO_4). The temperature at which the SO_3 condenses is termed the acid dew point. Operating at below the dew point results in the condensation of acids on boiler exhaust surfaces and corrosion of exposed metals.

5.5.2 Available Controls

Reduced Fuel Sulfur Content. The most effective means of controlling sulfur oxide emissions is by reducing the quantity of sulfur in the fuel. For oil fuels, this can be accomplished by switching to natural gas.

Flue Gas Desulfurization (FGD). Several technologies have been developed to remove sulfur oxide emissions from flue gases. Generally, these technologies use alkali materials (calcium sodium, potassium or magnesium) that combine with the SO_2 in the fuel gases to form salts. The salts are then removed from the gas steam as particulate matter and disposed.

Wet and dry FGD systems have been applied to numerous industrial and utility applications firing coal and oils with appreciable sulfur contents (greater than 0.5%).

5.6 SO_2 CONTROL TECHNICAL FEASIBILITY ANALYSES

As discussed previously, the change in fuel from distillate oil to natural gas is technically feasible. The only detrimental effect will be a small decrease in the boiler's efficiency.

The use of FGD system would be impractical and not technically feasible due to the small size of the units, their low fuel sulfur content, and the non-continuous operation of the smaller boilers.

5.7 SO_2 CONTROL COST-EFFECTIVENESS ANALYSES

Presented in Table 5-6 is a summary of the cost-effectiveness values for the substitution of very low nitrogen fuels for the base fuel oil. The cost-effective value is estimated to be approximately $88,000/t.

5.8 DETERMINATION OF BACT FOR SO_2

Since the application of more effective control technologies than the assumed baseline BACT technology has been shown to be to costly, BACT will be the use of low-sulfur distillate fuel oil that is commercially available in the Richland area.

TABLE 5-6
TOP-DOWN BACT IMPACT ANALYSIS FOR SO_2
DISTILLATE OIL-FIRED BOILER WITH 26.3 MMBTU/HR HEAT INPUT
(700 BHP)

Control Technology	SO_2 Emissions		Economic Impacts				Detrimental Impacts (yes/no)	
	Annual[1] (t/y)	Reduction (t/y)	Capital Costs ($1000)	Annualized Costs[2] ($1000/y)	Average Cost Effectiveness ($1000/t)	Incremental Cost Effectiveness ($1000/t)	Energy	Environ-mental
Natural Gas	0.02	1.45	800[3]	128[4]	88.3	- - -	Yes	No
Baseline 0.05% S Distillate Oil	1.47	- - -	- - -	- - -	- - -	- - -	- - -	- - -

1. Based on a 25% capacity factor
2. 0.16 capitalization factor
3. Proportional cost of a $5 million natural gas pipeline from Richland to the 200 Areas
4. Assumes no fuel cost differential

SECTION 6.0

FORMALDEHYDE AIR QUALITY ANALYSIS

Formaldehyde is formed and released in very trace quantities in the exhausts of distillate oil and natural gas-fired boilers. A request has been made by Ecology to include an ambient air quality analysis of these emissions as part of the NOC. Washington State AAQS limits formaldehyde concentrations to less than 0.077 $\mu g/m^3$ on an annual basis at the site fenceline.

Unlike most industrial plants, locating an appropriate "fenceline" of the Hanford Site is not straightforward. As described in Section 2, the site is laid out over a 560 square mile area bounded by arid regions, and in some cases, the Columbia River.

For purposes of these analyses, the fenceline for the 200 Areas has been assumed to be the closest point of Highway 240 that runs diagonally across the Hanford Site and is used by the public. The closest distances from the 200 West and East Areas to Highway 240 are 5 km and 10 km, respectively. The actual boundary of the site from these areas is more than 13 miles making the use of the highway boundary conservative.

The 300 Area lies in close proximity to the Columbia River. For these analyses, the fenceline for the 300 Area has been assumed to be the nearest river shore since the public has access to the river.

6.1 APPROACH

Compliance will be demonstrated using SCREEN-3, a computer model developed by the EPA and approved by Ecology for the determination of the maximum receptor level air emissions concentrations. SCREEN-3 automatically selects a set of meteorological data to demonstrate a worst-case impact scenario. As requested by Ecology, a receptor height of 6 ft (1.7 m) has been used in these calculations.

Topographic maps of the Hanford Site were examined to determine appropriate terrain conditions at their respective "fencelines." In all cases, the elevations at the fencelines are below the base of the stacks. Assumed elevations have therefore been taken to be 0 feet, which is, again, conservative.

Six scenarios were selected, representing one large and one small boiler from each of the three areas at the Hanford Site. Projected flow conditions and stack geometries were based on the boiler specification data supplied to prospective vendors. SCREEN-3 was run using rural dispersion characteristics using the stack geometry and flow conditions presented in Table 6-1.

The effects of building downwash was incorporated into the calculations. As discussed in Section 3, the boilers will be housed in separate annex buildings physically removed from the existing buildings. Information on the proposed boiler groupings was discussed in Table 3-2 and 3-3. Associated building geometry data for the six boiler scenarios is presented in Table 6-2.

The approach used assumes that the largest impact of one of the two scenario boilers is representative of the maximum total impact from all the boilers within the area. Calculated values from the individual boilers are projected to the total boiler population on the basis of its proportional heat input. The larger total impact of the two scenario boilers is then taken to be the maximum total impact.

The emission rates for formaldehyde for distillate oil combustion were taken from AP-42 Table 1.3-9. The midrange for this table is 0.000319 lb/mmBtu. The emission rate for natural gas combustion is based on information obtained from Ventura County APCD (see Appendix G). The emission rate used was 0.0000409 lb/mmBtu.

SCREEN-3 calculations were made for each boiler operating under full load conditions. Projected results from the Screen-3 modeling are on the basis of 1-hour average concentrations. These values have been converted to annual concentrations using a multiplication factor of 0.1.

6.2 RESULTS OF THE SCREEN-3 CALCULATIONS

The results of the SCREEN-3 computations for the six selected boiler sizes are presented in Table 6-2. In all cases, the projected impacts of the individual boilers on fenceline concentrations are well below the state standard. Projecting these results to the entire boiler population within the associated areas also demonstrates no serious impacts.

TABLE 6-1

SCREEN-3 MODELING INPUTS
STACK GEOMETRY AND FLOW CONDITIONS

Parameter (units)	200 West Area		200 East Area		300 Area	
Boiler Size (BHP)	80	350	80	700	60	300
Annex Buildings						
Height (m)	4.3	5.5	4.3	5.5	4.3	4.9
Width (m)	5.5	11.0	5.5	11.0	6.1	8.5
Depth (m)	6.7	18.3	6.7	18.3	8.5	11.0
Stack						
Height (m)	7.3	8.5	7.3	8.5	7.3	8.5
Diameter (m)	0.31	0.46	0.31	0.61	0.31	0.46
Gas Flow						
Discharge (g/s)	0.00013	0.00054	0.00013	0.00106	0.000013	0.000062
Velocity (m/s)	6.4	10.9	6.4	11.7	4.8	9.5
Temperature (°K)	495	425	495	400	465	425

TABLE 6-2
MAXIMUM RECEPTOR LEVEL ANNUAL CONCENTRATIONS
($\mu g/m^3$)

Parameter	200 West Area		200 East Area		300 Area	
Receptor Location	Hwy 240		Hwy 240		Columbia River	
Distance (m)	5,000		10,000		600	
Elevation (m)	0		0		0	
Boiler Size (BHP)	80	350	80	700	60	300
Fenceline Concentration ($\mu g/m^3$)	0.00058	0.00184	0.00027	0.00173	0.0003	0.00062
Proportion of Area Heat Input (%)	4.0	17.5	3.7	31.1	1.9	9.6
Equivalent Total Impact ($\mu g/m^3$)	0.0145	0.0105	0.0073	0.0054	0.0156	0.0064
Proportion of 0.077 µg/m3 Limit (%)	18.8	13.6	9.5	7.0	20.2	8.3

SECTION 7.0

COMPLIANCE ASSURANCE PLAN

7.1 STARTUP COMPLIANCE TESTS

7.1.1 Emission Limits

Guaranteed maximum emission levels have been obtained from the boiler manufacturer for all boilers with a maximum heat input rate equal to or greater than 5 mmBtu/hr (see Appendix F). The following emission rates apply to these boilers:

No. 2 Distillate Oil	lb/mmBtu	Other Units
NO_X	0.150	115 ppm @ 3% O_2
CO	0.071	90 ppm @ 3% O_2
Particulate Matter (PM_{10})	0.011	
Volatile Organics (TOC's)	0.013	30 ppm @ 3% O_2
Sulfur Dioxides	0.051	0.05% sulfur distillate oil

Natural Gas	lb/mmBtu	Other Units
NO_X	0.037	30 ppm @ 3% O_2
CO	0.225	300 ppm @ 3% O_2
Particulate Matter (PM_{10})	0.012	
Volatile Organics (TOC's)	0.013	30 ppm @ 3% O_2
Sulfur Dioxides	0.0006	

No emission limits will be applied to the smaller boilers with heat input rates less than 5 mmBtu/hr. Low sulfur distillate oil will be used in the 200 Areas. Natural gas will be used in the 300 Area. "Good combustion practices" will be applied to all boilers.

7.1.2 Compliance Tests

Tests to demonstrate compliance with the above emission limits will be conducted on selected boilers within their 180 day project installation and shakedown periods. All tests will be conducted using EPA and Ecology approved procedures with the test boilers operating at full rated loads. For those boilers burning distillate oil, certification of NO_X compliance will be contingent on burning an oil with a nitrogen content no greater than 400 ppm (0.04%). Background concentrations of PM_{10} (carried into the boiler with the combustion air) are to be tested separately and deducted from the stack emission values.

Tests are to be conducted on a limited number of boilers (maximum of five) selected on the basis of boiler capacity and fuel type. The procedure for selecting the test boilers will be agreed to by DOE/RL and Ecology prior to conducting the tests.

For discussion, it is suggested that one of the boilers in each of the following five capacity/fuel type categories be included in the test program:

Distillate Oil-Fired Boilers	Number of Units
200 BHP	5
350 BHP	3
700 BHP	2
Natural Gas-Fired Boilers	
200 BHP	2
300 BHP	4

The total installed capacity of these boilers (5,450 BHP) represent approximately 75% of the total installed capacity of all boilers.

7.2 COMPLIANCE ASSURANCE

In this and subsequent sections, reference to "DOE/RL/Contractor" refers to the joint responsibility of DOE/RL and its contractors that will operate and maintain the boilers.

7.2.1 Operating and Maintenance (O&M) Practices

DOE/RL/Contractor will obtain O&M manuals from the boiler manufactures. These manuals will become the basis for the O&M practices to be used on the site. The manuals will be made available for review by Ecology on request.

7.2.2 Boiler Tuneups

Maintaining good combustion practices is an important part of maintaining minimum emission levels of all criteria pollutants. Readjustments of the combustion control settings during the tuneups allow the boilers to maintain minimum excess air levels and NO_X emissions without adversely impacting the release of combustible emissions (CO, VOC's and particulate). This practice is consistent with the compliance assurance programs under development by EPA, Ecology and several local regulatory agencies in the state for small industrial and commercial boilers.

Periodic boiler tuneups will be conducted on all boilers by the boiler manufacturers as part of the purchase contract. It is suggested that these tuneup activities be conducted annually on all boilers with heat input rates greater than or equal to 5 mmBtu/hr and subject to emission limit requirements. Smaller boilers are to be tuned once every two years.

7.2.3 Follow-up Compliance Tests

It is suggested that follow-up compliance tests be conducted on selected boilers once every five years. The selection process for the boilers and the test methods will be consistent with that described in Section 7.1.2 above.

7.3 RECORDKEEPING

DOE/RL/Contractor will maintain appropriate records of the fuel use on each individual boiler on a monthly basis. These data, along with the emission factors presented in this document (or as mutually agreed on with Ecology) will be used to determine monthly emission levels for individual boilers, and collectively for the 200 East and West, and 300 Areas.

AP-42 factors will also be used to determine air toxic emission rates as required by Ecology and consistent with current reporting practices.

Logs of boiler tuneups and significant boiler maintenance activities will be maintained.

7.4 REPORTING

DOE/RL/Contractor will prepare a report to Ecology containing annual emissions inventories consistent with current reporting practices.

APPENDIX A:
ANNUAL EMISSIONS INVENTORIES
(1986-1995)

TABLE A-1
ANNUAL NO_X EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	167.6	55.4	25.0	46.8	14.3	- - -	- - -	- - -	- - -	- - -
#2 + #3 Combustion Engineering	3.4	5.7	140.0	0.6	- - -	- - -	- - -	- - -	- - -	- - -
200 East										
#1 - #3 Erie City #4 + #5 Riley	428.1	333.0	408.3	206.7	178.0	150.0	133.4	174.2	84.9	194.4
#6 Trane	1.0	0.3	1.5	0.2	- - -	- - -	- - -	- - -	- - -	- - -
200 West										
#1 - #4 Erie City	181.5	183.0	189.8	200.0	168.6	171.8	171.0	160.2	202.4	30.3
Babcock & Wilcox	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	0.6
300										
#1 Nationwide	- - -	- - -	- - -	7.0	23.1	25.8	25.5	41.0	24.5	35.8
#2 Riley	3.4	0.3	1.4	20.4	16.2	37.3	21.4	12.7	18.7	10.2
#3 International	52.0	37.6	40.8	22.2	- - -	- - -	- - -	- - -	1.0	- - -
#4 International	45.4	45.6	35.2	16.6	- - -	- - -	- - -	- - -	- - -	- - -
#5 International	52.0	64.1	44.0	18.9	- - -	- - -	- - -	- - -	- - -	- - -
#6 Riley	0.0	0.5	1.8	21.1	25.9	7.3	9.4	12.3	11.5	5.6
Total	934.4	725.5	887.8	560.4	426.0	392.3	360.6	400.3	343.0	276.8

TABLE A-2
ANNUAL SO_2 EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	837.0	276.7	125.0	233.5	71.3	---	---	---	---	---
#2 + #3 Combustion Engineering	11.0	18.5	457.2	2.0	---	---	---	---	---	---
200 East										
#1 - #3 Erie City #4 + #5 Riley	831.3	646.5	792.7	401.4	345.6	291.3	259.1	231.9	124.8	248.0
#6 Trane	2.4	0.8	3.6	0.5	---	---	---	---	---	---
200 West										
#1 - #4 Erie City	352.5	355.3	368.4	388.4	327.4	333.6	331.9	213.2	297.6	38.7
Babcock & Wilcox	---	---	---	---	---	---	---	---	---	0.2
300										
#1 Nationwide	---	---	---	34.8	115.4	129.0	127.4	204.8	122.2	178.9
#2 Riley	16.9	1.7	6.9	102.0	80.7	186.5	106.9	63.5	93.3	50.7
#3 International	101.0	73.0	79.2	43.1	---	---	---	---	1.6	---
#4 International	88.2	88.5	68.4	32.2	---	---	---	---	---	---
#5 International	100.9	124.5	85.4	36.1	---	---	---	---	---	---
#6 Riley	0.0	2.6	8.9	105.4	129.3	36.4	46.7	61.2	57.4	27.9
Total	2341	1588	1996	1380	1070	977	872	775	697	544

TABLE A-3
ANNUAL CO EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	15.2	5.0	2.3	4.3	1.3	- - -	- - -	- - -	- - -	- - -
#2 + #3 Combustion Engineering	0.8	1.4	35.0	0.2	- - -	- - -	- - -	- - -	- - -	- - -
200 East										
#1 - #3 Erie City #4 + #5 Riley	156.3	121.5	149.0	75.5	65.0	54.8	48.7	63.6	31.0	70.9
#6 Trane	0.2	0.1	0.4	0.1	- - -	- - -	- - -	- - -	- - -	- - -
200 West										
#1 - #4 Erie City	66.3	66.8	69.3	73.0	61.5	62.7	62.4	58.5	73.9	11.1
Babcock & Wilcox	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	0.2
300										
#1 Nationwide	- - -	- - -	- - -	0.6	2.1	2.4	2.3	3.7	2.2	3.3
#2 Riley	0.3	0.0	0.1	1.9	1.5	3.4	1.9	1.2	1.7	0.9
#3 International	19.0	13.7	14.9	8.1	- - -	- - -	- - -	- - -	0.4	- - -
#4 International	16.6	16.6	12.9	6.1	- - -	- - -	- - -	- - -	- - -	- - -
#5 International	19.0	23.4	16.1	6.9	- - -	- - -	- - -	- - -	- - -	- - -
#6 Riley	0.0	0.1	0.2	1.9	2.3	0.7	0.9	1.1	1.1	0.5
Total	293.7	248.7	300.2	178.4	133.7	123.9	116.2	128.0	110.3	86.8

TABLE A-4
ANNUAL PM_{10} EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	51.1	16.9	7.6	14.3	4.4	- - -	- - -	- - -	- - -	- - -
#2 + #3 Combustion Engineering	0.2	0.3	7.0	0.0	- - -	- - -	- - -	- - -	- - -	- - -
200 East										
#1 - #3 Erie City #4 + #5 Riley	0.8	0.6	0.8	0.5	0.3	0.3	0.3	0.3	0.2	0.4
#6 Trane	0.1	0.0	0.1	0.0	- - -	- - -	- - -	- - -	- - -	- - -
200 West										
#1 - #4 Erie City	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.1
Babcock & Wilcox	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	0.0
300										
#1 Nationwide	- - -	- - -	- - -	2.1	7.0	7.9	7.8	12.5	7.5	10.9
#2 Riley	1.0	0.1	0.4	6.2	4.9	11.4	6.5	3.9	5.7	3.1
#3 International	0.1	0.1	0.1	0.0	- - -	- - -	- - -	- - -	0.0	- - -
#4 International	0.1	0.1	0.1	0.0	- - -	- - -	- - -	- - -	- - -	- - -
#5 International	0.1	0.1	0.1	0.0	- - -	- - -	- - -	- - -	- - -	- - -
#6 Riley	0.0	0.2	0.5	6.5	7.9	2.2	2.9	3.7	3.5	1.7
Total	53.8	18.7	17.1	30.0	24.9	22.1	17.7	20.8	17.2	16.2

TABLE A-5
ANNUAL TOTAL PM EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	58.81	19.44	8.78	16.41	5.01	0.0	0.0	0.0	0.0	0.0
#2 + #3 Combustion Engineering	.34	.57	14.0	.06	0.0	0.0	0.0	0.0	0.0	0.0
200 East										
#1 - #3 Erie City #4 + #5 Riley	.39	.31	.37	.19	.16	.14	.12	.16	.08	.18
#6 Trane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200 West										
#1 - #4 Erie City	1.75	1.76	1.83	1.93	1.62	1.66	1.65	1.54	1.95	.29
Babcock & Wilcox	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	- - -	0.6
300										
#1 Nationwide	- - -	- - -	- - -	7.41	8.10	9.06	8.95	14.39	8.58	12.57
#2 Riley	1.19	.12	.48	7.16	5.67	13.10	7.51	4.46	6.56	3.56
#3 International	.5	.36	.39	.21	0.0	0.0	0.0	0.0	0.01	0.0
#4 International	.44	.09	.34	.16	0.0	0.0	0.0	0.0	0.0	0.0
#5 International	.5	.62	.42	.18	0.0	0.0	0.0	0.0	0.0	0.0
#6 Riley	0.0	.16	.62	2.44	9.08	2.56	3.28	4.3	4.04	1.96
Total	67.7	26.7	31.0	38.0	31.2	27.8	22.7	26.4	22.0	20.3

TABLE A-6
ANNUAL VOC EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	.85	.281	.13	.24	.03	0.0	0.0	0.0	0.0	0.0
#2 + #3 Combustion Engineering	.03	.06	1.40	.01	0.0	0.0	0.0	0.0	0.0	0.0
200 East										
#1 - #3 Erie City #4 + #5 Riley	1.56	1.22	1.49	.75	.65	.55	.49	.64	.31	.71
#6 Trane	.01	0.0	.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200 West										
#1 - #4 Erie City Babcock & Wilcox	.66	.67	1.25	.73	.62	.63	.62	.58	.74	.11
300										
#1 Nationwide	0.0	0.0	0.0	.11	.12	.13	.13	.21	.12	.18
#2 Riley	.02	0.0	.01	.10	.08	.19	.04	.06	.10	.05
#3 International	.19	.14	.15	.08	0.0	0.0	0.0	0.0	0.0	0.0
#4 International	.17	.17	.13	.06	0.0	0.0	0.0	0.0	0.0	0.0
#5 International	.19	.23	.16	.07	0.0	0.0	0.0	0.0	0.0	0.0
#6 Riley	0.0	0.0	.01	.04	.13	.04	.05	.06	.06	.03
Total	3.68	2.77	4.18	2.19	1.67	1.53	1.40	1.56	1.33	1.09

TABLE A-7
ANNUAL LEAD EMISSION INVENTORIES (1986 TO 1995)

Area/Boiler Number and Manufacturer	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
100 N										
#1 Foster Wheeler	.09	.03	0.01	.03	.01	0.0	0.0	0.0	0.0	0.0
#2 + #3 Combustion Engineering	0.0	0.0	.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200 East										
#1 - #3 Erie City #4 + #5 Riley	.39	.31	.37	.19	.16	.14	.12	.16	.08	.18
#6 Trane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200 West										
#1 - #4 Erie City	0.0	0.0	0.0	.01	.01	.01	.01	.02	.01	.02
Babcock & Wilcox	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
300										
#1 Nationwide	0.0	0.0	0.0	.01	.01	.01	.01	.02	.01	.02
#2 Riley	0.0	0.0	0.0	0.0	.01	.01	.02	.01	.01	.01
#3 International	.05	.03	.04	.02	0.0	0.0	0.0	0.0	0.0	0.0
#4 International	.04	.04	.03	.02	0.0	0.0	0.0	0.0	0.0	0.0
#5 International	.05	.06	.04	.02	0.0	0.0	0.0	0.0	0.0	0.0
#6 Riley	0.0	0.0	0.0	0.0	.01	0.0	.01	.01	.01	0.0
Total	.79	.64	.68	.48	.36	.33	.31	.34	.29	.23

APPENDIX B:
NEW BOILER INVENTORY

Appendix B

JOHNSON CONTROLS, INC.
HANFORD 200/300 AREA STEAM PLANT REPLACEMENT
ENERGY CONSERVATION MEASURES

BOILER INVENTORY MARCH 14, 1996

ASSUMED FACTORS:

BHP =	0.033475	mmBtu/hr
Operations	8760	hr/yr

Emission Factors (lb/mmBtu)	Distillate Oil	Natural Gas	Comments
NOX > or = 5 mmBtu/hr	0.15	0.037	Low-NOX Burners (115 & 30 ppm 3% O2)
< 5 mmBtu/hr	0.18	0.1	140 & 80 ppm (3% O2)
SO2	0.051	0.0006	AP-42 (0.05% S Distillate Oil)
CO > or = 5 mmBtu/hr	0.071	0.225	90 & 300 ppm (3% O2)
< 5 mmBtu/hr	0.071	0.225	90 & 300 ppm (3% O2)
PM10	0.011	0.012	AP-42 (Margin for distillate oil)
Total PM	0.015	0.012	AP-42
VOC's (TOC)	0.013	0.013	30 ppm (3% O2)
Lead	8.9E-06	0	AP-42 + VCAPCD

Note: The 700 BHP Boilers operating in the Annex near the 242-A Building are limited to: 8760 hrs/yr

200 WEST AREA - DISTILLATE OIL FUEL

BUILDING	BOILER HP	EFF	ENERGY IN (mmBtu/hr)	Annual Emissions (t/yr) NOX	SO2	CO	PM10	PM	VOC'S	LEAD
234-5Z	350	85.80%	13.66	8.97	3.05	4.25	0.66	0.90	0.78	0.000532
	350	85.80%	13.66	8.97	3.05	4.25	0.66	0.90	0.78	0.000532
	350	85.80%	13.66	8.97	3.05	4.25	0.66	0.90	0.78	0.000532
222-S/2716-S	200	88.20%	7.59	4.99	1.70	2.36	0.37	0.50	0.43	0.000296
	200	88.20%	7.59	4.99	1.70	2.36	0.37	0.50	0.43	0.000296
283-W/B-604	200	88.20%	7.59	4.99	1.70	2.36	0.37	0.50	0.43	0.000296
HILL CONST CMPLX	80	86.00%	3.11	2.46	0.70	0.97	0.15	0.20	0.18	0.000121
272-W/2707-W/277-W	250	88.00%	9.51	6.25	2.12	2.96	0.46	0.62	0.54	0.000371
TOTALS	1980		76.36	50.58	17.06	23.75	3.68	5.02	4.35	0.002977

200 EAST AREA - DISTILLATE OIL FUEL

BUILDING	BOILER HP	EFF	ENERGY IN (mmBtu/hr)	Annual Emissions (t/yr) NOX	SO2	CO	PM10	PM	VOC'S	LEAD
2707-E/275-E/2715-EC	80	86.00%	3.11	2.46	0.70	0.97	0.15	0.20	0.18	0.000121
225-B	150	87.50%	5.74	3.77	1.28	1.78	0.28	0.38	0.33	0.000224
242-A	200	86.00%	7.78	5.11	1.74	2.42	0.38	0.51	0.44	0.000303
hr/yr = 8760	700	89.10%	26.30	17.28	5.87	8.18	1.27	1.73	1.50	0.001025
hr/yr = 8760	700	89.10%	26.30	17.28	5.87	8.18	1.27	1.73	1.50	0.001025
East/West Tank Farm	150	86.00%	5.84	3.84	1.30	1.82	0.28	0.38	0.33	0.000228
283-E/B-604	200	88.20%	7.59	4.99	1.70	2.36	0.37	0.50	0.43	0.000296
TOTALS	2180		82.66	54.72	18.47	25.71	3.98	5.43	4.71	0.003222

Appendix B

300 AREA - NATURAL GAS FUEL

BUILDING	BOILER HP	EFF	ENERGY IN (mmBtu/hr)	Annual Emissions (t/yr) NOX	SO2	CO	PM10	PM	VOC'S	LEAD
305	40	81.00%	1.65	0.72	0.00	1.63	0.09	0.09	0.09	0
3705	15	81.00%	0.62	0.27	0.00	0.61	0.03	0.03	0.04	0
306-E	150	84.30%	5.96	0.97	0.02	5.87	0.31	0.31	0.34	0
328	30	81.00%	1.24	0.54	0.00	1.22	0.07	0.07	0.07	0
337/337-B	60	80.50%	2.50	1.09	0.01	2.46	0.13	0.13	0.14	0
	60	80.50%	2.50	1.09	0.01	2.46	0.13	0.13	0.14	0
3717/3717-B/3706	80	82.00%	3.27	1.43	0.01	3.22	0.17	0.17	0.19	0
3709-A	10	81.00%	0.41	0.18	0.00	0.41	0.02	0.02	0.02	0
331	300	82.00%	12.25	1.98	0.03	12.07	0.64	0.64	0.70	0
	300	82.00%	12.25	1.98	0.03	12.07	0.64	0.64	0.70	0
327	200	84.90%	7.89	1.28	0.02	7.77	0.41	0.41	0.45	0
325	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
329	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
323/3760	50	81.00%	2.07	0.91	0.01	2.04	0.11	0.11	0.12	0
326	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
	100	84.40%	3.97	1.74	0.01	3.91	0.21	0.21	0.23	0
3720	125	83.20%	5.03	0.82	0.01	4.96	0.26	0.26	0.29	0
3745	10	81.00%	0.41	0.18	0.00	0.41	0.02	0.02	0.02	0
324	300	82.00%	12.25	1.98	0.03	12.07	0.64	0.64	0.70	0
	300	82.00%	12.25	1.98	0.03	12.07	0.64	0.64	0.70	0
382/382B/382C/382D	200	84.90%	7.89	1.28	0.02	7.77	0.41	0.41	0.45	0
318	30	81.00%	1.24	0.54	0.00	1.22	0.07	0.07	0.07	0
320	125	83.20%	5.03	0.82	0.01	4.96	0.26	0.26	0.29	0
	125	83.20%	5.03	0.82	0.01	4.96	0.26	0.26	0.29	0
TOTALS	3110		125.50	31.29	0.33	123.68	6.60	6.60	7.15	0
TOTAL TOTALS	7270		284.53	136.59	35.85	173.14	14.26	17.04	16.20	0.006199

APPENDIX C:
QUARTERLY EMISSIONS INVENTORIES

TABLE C-1
NO_X EMISSION QUARTERLY INVENTORIES (July 1994 TO June 1996)

Area/Boiler Number and Manufacturer	1994		1995		12 Month Totals (tons)	1995		1996*		12 Month Total (tons)	12 Month Average (t/y)
	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter		3rd Quarter	4th Quarter	1st Quarter	2nd Quarter		
200 East											
#1 - #3 Erie City #4 + #5 Riley	0	0	50.6	47.0	97.6	36.3	60.4	65.6	41.6	203.9	150.8
200 West											
#1 - #4 Erie City	31.7	88.9	30.3	0	150.9	7.8	0	0	0	7.8	79.4
Babcock & Wilcox	0	0	0	0	0	0	0.6	0.1	0	0.7	0.4
300											
#1 Nationwide	1.4	6.7	10.6	9.4	28.1	4.9	11.0	0	0	15.9	22.0
#2 Riley	1.9	6.4	6.4	0.3	15.0	1.3	7.9	17.0	6.3	32.5	23.8
#6 Riley	2.0	2.2	4.4	0.4	9.0	0	0.8	2.6	2.5	5.9	7.5
Totals	36.9	104.2	102.3	57.1	300.6	50.2	80.7	85.4	50.3	266.7	283.7

* Preliminary (not validated) data

TABLE C-2
CO EMISSION QUARTERLY INVENTORIES (JULY 1994 TO JUNE 1996)

Area/Boiler Number and Manufacturer	1994		1995		12 Month Totals (tons)	1995		1996*		12 Month Total (tons)	12 Month Average (t/y)
	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter		3rd Quarter	4th Quarter	1st Quarter	2nd Quarter		
200 East											
#1 - #3 Erie City #4 + #5 Riley	0	0	18.5	17.2	35.7	13.3	22.1	24.0	15.2	74.6	55.2
200 West											
#1 - #4 Erie City	11.6	32.5	11.1	0	55.2	0	0	0	0	0.0	27.6
Babcock & Wilcox	0	0	0	0	0	0	0.2	0.0	0	0.2	0.1
300											
#1 Nationwide	0.1	0.6	1.0	0.8	2.5	0.4	1.0	0	0	1.4	2.0
#2 Riley	0.1	0.6	0.6	0.0	2.2	0.1	0.7	1.7	0.5	3.0	2.6
#6 Riley	0.2	0.2	0.4	0.0	0.6	0	0.1	0.2	0.2	0.5	0.5
Totals	12.0	33.8	31.5	18.1	95.4	13.8	24.0	25.8	16.0	79.6	87.5

* Preliminary (not validated) data

APPENDIX D:

State of California
AIR RESOURCES BOARD

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

Prepared by

Criteria Pollutants Branch
Stationary Source Division

Approved by

the Technical Review Group
of the
California Air Pollution Control Officers' Association

July 18, 1991

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Table of Contents

Contents | Page

INTRODUCTION.....1

I. RACT/BARCT RECOMMENDATION.....1

A. RACT Discussion.....1
B. BARCT Discussion.....4

II. CONTROL TECHNOLOGY.....6

A. Low-NOx Burners.....7
B. Flue Gas Recirculation.....8
C. Selective Noncatalytic Reduction.....8
D. Selective Catalytic Reduction.....8

III. COST-EFFECTIVENESS.....9

IV. IMPACTS.....10

A. Economic.....10
B. Air Quality.....10
C. Hazards.....10
D. Energy.....11

V. REFERENCES.....12

APPENDICES

A. PROPOSED RACT/BARCT DETERMINATION

B. SCAQMD RULE 1146.1 - Emissions of Oxides of Nitrogen From Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.

C. SCAQMD RULE 1146 - Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

D. SCAQMD RULE 1109 - Emissions of Oxides of Nitrogen From Boilers and Process Heaters in Petroleum Refineries

E. VCAPCD RULE 74.15 - Boilers, Steam Generators and Process Heaters

F. SIGNIFICANT COMMENTS AND RESPONSES

INTRODUCTION

This report presents the proposed determinations of reasonably available control technology (RACT) and best available retrofit control technology (BARCT) for industrial, institutional, and commercial boilers, steam generators, and process heaters. The RACT/BARCT Determination is presented in Appendix A of this document. The determinations follow the "California Clean Air Act Guidance for the Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology," approved by the California Air Resources Board (ARB) on April 13, 1990. The determinations have been reviewed and approved by the Technical Review Group (TRG) of the California Air Pollution Control Officers' Association (CAPCOA).

In developing the proposed RACT and BARCT determinations, the staff reviewed a statewide suggested control measure (SCM) and several district rules. Tables 1 and 2 present summaries of the SCM and the district rules that the staff reviewed. The Technical Support Document (TSD) for the SCM is available upon request. The complete texts of the applicable district rules are contained in Appendices B-E.

I. RACT/BARCT RECOMMENDATION

A. RACT Discussion

On April 29, 1987, the TRG approved a suggested control measure for the control of emissions of oxides of nitrogen (NOx) from industrial, institutional, and commercial boilers, steam generators and process heaters. This SCM was subsequently approved by the ARB on September 10, 1987. The SCM applies to units with rated heat inputs of 10 million British thermal units per hour (MMBtu/hr) and up, except units with rated heat inputs of greater than 40 MMBtu/hr that are based in petroleum refineries.

The lowest emission limits contained in the SCM apply to units with rated heat inputs of greater than or equal to 20 million Btu per hour and less than or equal to 150 million Btu per hour, operating with annual capacity factors of greater than 10 percent. The limits for these units are 70 parts per million by volume (ppmv) NOx for gaseous fuel operations and 115 ppmv NOx for number 1 or number 2 grade fuel oil.

For the RACT determination, we have extended the application of these limits to all units with rated heat inputs of greater than or equal to 5 million Btu per hour, operating with annual heat inputs of greater than or equal to 90,000 therms. We have also applied the limit for operating on number 1 or number 2 grade fuel oil to operation with all types of nongaseous fuels. Units which normally burn only gas are allowed a 150 ppmv NOx emission limit for burning nongaseous fuel for not more than 168 hours per year, if gas is unavailable for purchase.

Table 1

Emission Limits Contained in the Suggested Control Measure
Approved by the Air Resources Board on September 10, 1987

Rated[a/] Heat Input	Annual Capacity Factor	Fuel Type	NO_x[b/] Emission Limits
≥20 and ≤150 MMBtu/hr	>10.0%	Gas	70 ppmv NO_x or 0.08 lbs NO_2/MMBtu
		Fuel Oil #1 or #2	115 ppm NO_x or 0.15 lbs NO_2/MMBtu
		Other Fuel Oil	150 ppmv NO_x or 0.20 lbs NO_2/MMBtu
>150 MMBtu/hr	>5.0%	Gas	85 ppmv NO_x or 0.10 lbs NO_2/MMBtu
		Fuel Oil #1 or #2	135 ppmv NO_x or 0.18 lbs NO_2/MMBtu
		Other Fuel Oil	165 ppmv NO_x or 0.22 lbs NO_2/MMBtu

a/ Units with rated heat inputs of greater than or equal to 10 MMBtu/hr, and less than 20 MMBtu/hr, and with annual capacity factors of greater than 10.0%, are subject to other requirements.

b/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

Table 2

Summary District Rules Reviewed for NOx Emissions from Non-Utility Boilers and Process Heaters

Rated Heat Input	Annual Heat Input or Capacity Factor	NOx[c/] Emission Limits	CO[c/] Emission Limits
-------SCAQMD's Rule 1146.1, Boilers and Process Heaters (10/5/90)----------			
≥2 and <5 MMBtu/hr	>18,000 therms[a/]	30 ppmv or 0.037 lbs NO_2/MMBtu	400 ppmv
-------SCAQMD's Rule 1146, Boilers and Process Heaters (9/9/88, 1/6/89)-----			
≥5 MMBtu/hr	≤90,000 therms[b/]	40 ppmv or 0.05 lbs NO_2/MMBtu	400 ppmv
≥40 MMBtu/hr	>25%	30 ppmv	400 ppmv
-------SCAQMD's Rule 1109, Boilers and Process Heaters - Petroleum---------- Refineries, (11/1/85, 8/5/88)			
>40 MMBtu/hr	≥10%	0.03 lbs NO_2/MMBtu @ maximum rated capacity	
-------VCAPCD's Rule 74.15, Boilers and Process Heaters, (3/28/89)----------			
≥5 MMBtu/hr	≥90,000 therms[b/]	40 ppmv	400 ppmv

a/ Units with annual heat inputs of less than 18,000 therms are subject to other requirements.

b/ Units with annual heat inputs of less than 90,000 therms are subject to other requirements.

c/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

A summary of the RACT determination is presented in Table 3.

B. BARCT Discussion

As shown in Table 2, both the South Coast Air Quality Management District (SCAQMD) and the Ventura County Air Pollution Control District (VCAPCD) have adopted source specific rules for NOx emission control on non-electric-generating boilers, steam generators, and process heaters. SCAQMD Rule 1109, adopted November 1, 1985, and amended August 5, 1988, applies to units with rated heat inputs of greater than 40 MMBtu/hr located at petroleum refineries. SCAQMD Rule 1146, adopted September 9, 1988, and amended January 6, 1989, applies to units with rated heat inputs of 5 MMBtu/hr and up not located at petroleum refineries. SCAQMD Rule 1146.1, adopted October 5, 1990, applies to units with rated heat inputs from 2 MMBtu/hr to less than 5 MMBtu/hr. VCAPCD Rule 74.15, adopted March 28, 1989, applies to units with rated heat inputs of 5 MMBtu/hr and up, except water heaters.

The emission limits contained in district rules are 30 ppmv NOx for units with rated heat inputs of greater than or equal to 2 million Btu per hour and less than 5 million Btu per hour, having annual heat inputs of greater than 18,000 therms; 40 ppmv NOx for units with rated heat inputs of greater than or equal to 5 million Btu per hour, having annual heat inputs of greater than 90,000 therms; 30 ppmv NOx for units with rated heat inputs of greater than or equal to 40 million Btu per hour, operating at annual capacity factors of greater than 25 percent; and 0.03 pounds NO_2 per million Btu of heat input for units operating at maximum rated capacity with rated heat inputs of greater than 40 million Btu per hour, sited at petroleum refineries and operating at annual capacity factors of greater than or equal to 10 percent.

For the BARCT determination, we have applied the 30 ppmv NOx emission limit to all units burning gas, having rated heat inputs of greater than or equal to 5 million Btu per hour and operating with annual heat inputs of greater than or equal to 90,000 therms. For units burning nongaseous fuels, we have applied the 40 ppmv NOx emission limit to all units having rated heat inputs of greater than or equal to 5 million Btu per hour, operating with annual heat inputs of greater than or equal to 90,000 therms. Units which normally burn only gas are allowed a 150 ppmv NOx emission limit for burning nongaseous fuel for not more than 168 hours per year, if gas is unavailable for purchase.

Table 3

RACT/BARCT Summary for Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters

Standards

---------- RACT ----------

Rated Heat Input	Annual[a/] Heat Input	Fuel Type	NOx[b/] Emission Limits	CO[b/] Emission Limits
≥ 5 MMBtu/hr	≥ 90,000 therms	Gas	70 ppmv[c/]	400 ppmv
		Other	115 ppmv[d/]	400 ppmv
		Exemption[g/]	150 ppmv[h/]	400 ppmv

---------- BARCT ----------

Rated Heat Input	Annual[a/] Heat Input	Fuel Type	NOx[b/] Emission Limits	CO[b/] Emission Limits
≥ 5 MMBtu/hr	≥ 90,000 therms	Gas	30 ppmv[e/]	400 ppmv
		Other	40 ppmv[f/]	400 ppmv
		Exemption[g/]	150 ppmv[h/]	400 ppmv

---

a/ Units with annual heat inputs of less than 90,000 therms are subject to other requirements.

b/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

c/ 0.084 pounds NO_2 per MMBtu of heat input.

d/ 0.150 pounds NO_2 per MMBtu of heat input.

e/ 0.036 pounds NO_2 per MMBtu of heat input.

f/ 0.052 pounds NO_2 per MMBtu of heat input.

g/ For not more than 168 hours per calendar year, only when gas is not available for purchase.

h/ 0.215 pounds NOx per MMBtu of heat input.

We chose 30 ppmv as the uniform BARCT NOx emission limit for gas firing of all industrial, institutional, and commercial boilers, steam generators, and process heaters. This uniform emission limit reflects improvements in technology which have occurred in the last few years. We believe that most units can meet this limit by installing new burners with flue gas recirculation. Some units may need to add selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems. We believe that 30 ppmv is the appropriate BARCT NOx emission limit due to the many units currently operating within this limit without the use of flue gas emission controls. New units of the near future may achieve emission limits below 15 ppmv NOx without the use of flue gas emission controls. However, for districts which have recently adopted rules which allow higher emissions, the incremental cost-effectiveness of requiring 30 ppmv may be high for some affected units. Therefore, districts which have adopted rules covering the applicability of this determination, within three years prior to the date of approval of this determination, are deemed to comply with this determination.

In the SCAQMD, specially blended low-NOx fuel oil, which has low sulfur, nitrogen, and aromatic hydrocarbon contents, is being used to meet the 40 ppmv limit of Rule 1146. Since the low-NOx fuel oil is blended in small quantities, it is much more expensive than number 2 fuel oil. Therefore, this low-NOx fuel oil is being used primarily for dual fuel firing capability at this time. Methanol is also being used in the SCAQMD to meet the 40 ppmv limit with dual fuel firing capability. We believe that, in the future, liquid fuel firing at 40 ppmv NOx may be economically competitive with gas firing at 30 ppmv NOx.

A summary of the BARCT determination is also presented in Table 3.

II. CONTROL TECHNOLOGY

Nitric oxide (NO) forms in process equipment such as boilers and heaters, which operate on the combustion of fuel and air. The NO may then be emitted to the atmosphere along with other products of combustion in the flue gas. Smaller amounts of nitrogen dioxide (NO_2) form in the combustion process, and some NO oxidizes to NO_2 in the stack.

We refer to NO and NO_2 cumulatively as oxides of nitrogen (NO_x), and we quantify NO_x emissions as parts per million (ppm) by volume, relative to dry stack gases at 3 percent O_2. Alternately, we may quantify NO_x emissions as pounds of NO_2 per million British thermal unit (MMBtu) of fuel input to the process, based on the higher heating value (HHV) and flow rate of the fuel.

The formation of NO by combustion processes is governed primarily by (1) the chemically-bound nitrogen content of the fuel, (2) the oxygen concentration of the flame, (3) the temperature of the flame, and (4) the length of time for which the combustion gases are held at the flame temperature.

Chemically-bound nitrogen of 1000 ppm by weight in fuel oil could result in NO formation of up to 83 ppm by volume, relative to dry stack gases at 3 percent O_2. This estimate is based on 65 percent conversion of fuel-nitrogen to NO. For higher fuel-nitrogen contents the percent conversion is lower. For lower fuel-nitrogen contents, the percent conversion is higher. Residual fuel oils may have nitrogen contents of between 1000 ppm and 8000 ppm by weight. In California, distillate fuel oils with nitrogen contents between 200 and 600 ppm by weight are typically available. By 1994, distillate fuel oils with nitrogen contents below 10 ppm by weight may be available as a result of statewide regulations limiting the sulfur content of motor vehicle diesel fuel. Chemically-bound nitrogen of 10 ppm in fuel oil could not convert to more than 1 ppm of NO. Due partly to chemically-bound nitrogen in fuel oils, the combustion of fuel oils produces more NO than the combustion of natural gas at the same conditions.

Generally, premixed flames, such as in natural gas combustion, will produce less NO than diffusion flames, such as in oil droplet combustion, with the same amount of excess air. This is because the peak temperatures in diffusion flames occur at surfaces of theoretically correct air-to-fuel ratios, while the peak temperatures for premixed flames are lower due to excess-air dilution.

For most applications reducing NOx emissions from industrial, institutional, and commercial boilers, steam generators, and process heaters can be broken down into four methods. These are (1) retrofitting of low-NOx-emitting burners, (2) retrofitting of flue-gas-recirculation systems (3) installation of ammonia injection systems for selective noncatalytic reduction, and (4) installation of ammonia injection systems along with catalytic reactors for selective catalytic reduction. These methods are discussed below.

A. Low-NOx Burners

Low-NOx burners employ low excess air combustion, air staging, fuel staging, or combustion product recirculation to lower NOx formation in the flame. Low excess air combustion and combustion product recirculation decrease the oxygen available for NOx formation. Combustion product recirculation also lowers the bulk flame temperature, and consequently lowers the NOx formation rate and equilibrium concentration. Staged-air burners lower available oxygen at points in the combustion chamber where the temperature is high. Staged-fuel burners lower the temperature at points in the combustion chamber where available oxygen is high. Retrofitting of low-NOx burners may require derating of equipment, because flame lengths may be significantly increased.

Low-NOx burners are applicable to most gas-fired and oil-fired units. For gas-fired units, the control effectiveness ranges from 10 to 55 percent. For units fired with low-nitrogen oil, the control effectiveness is expected to be within the same range.

B. Flue Gas Recirculation

Flue gas recirculation (FGR) for NOx control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the furnace windbox. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone.

A retrofit installation of FGR consists of adding a fan, ductwork, dampers, and controls as well as possibly having to increase existing fan horsepower due to increased draft loss.

FGR is an effective control technique for both gas-fired and distillate oil-fired units. FGR is not effective at reducing NOx formation originating from fuel-bound nitrogen. The control effectiveness of flue gas recirculation ranges from 60 to 70 percent for gas-fired units. The control effectiveness of FGR for units firing low-nitrogen oil is expected to be within the same range.

C. Selective Noncatalytic Reduction

Exxon Research and Engineering Company has developed, patented, and is offering for license, a noncatalytic process called Thermal DeNOx for removing oxides of nitrogen from flue gas in stationary combustion sources. Thermal DeNOx is based on the gas phase homogeneous reaction between NOx in flue gas and ammonia (NH_3), which produces nitrogen and water.

In general, NH_3 is injected into the hot flue gas by means of either air or steam carrier gas at a point in the flue specifically selected to provide optimum reaction temperature and residence time. In the temperature range of 1600°F to 2200°F, the reaction occurs through the injection of NH_3 alone. Hydrogen (H_2) can also be injected along with NH_3 to extend the effectiveness range of the deNOx reaction down to 1300°F.

NOx reductions of up to 90 percent have been demonstrated on an oil field steam generators where favorable process conditions exist. DeNOx performance using earlier technology ranges from 50 to 70 percent reduction for most oil-fired and gas-fired process heaters and steam boilers.

D. Selective Catalytic Reduction

Selective catalytic reduction (SCR) refers to a process that chemically reduces NOx with NH_3 over a heterogeneous catalyst in the presence of oxygen (O_2). The process is termed selective because the reducing agent NH_3 preferentially attacks NOx rather than O_2. However, the O_2 enhances the reaction and is a necessary part of the reaction scheme. Thus, SCR is potentially applicable to flue gas under oxidizing conditions, greater than one percent O_2.

In theory a 1:1 stoichiometric molar ratio of NH_3 to NO is sufficient to reduce NOx to molecular nitrogen (N_2) and water vapor (H_2O). In practice a NH_3:NO ratio of 1:1 has typically reduced NOx emissions by 80 to 90 percent

with a residual NH_3 concentration of less than 20 ppmv. The optimum temperature range for the catalytic reaction is 570°F to 845°F.

SCR retrofitting requires a reactor, which contains the catalytic material, and an ammonia storage and injection system. Due to the increased pressure drop across the reactor, some increase in boiler fan horsepower, or possibly a new fan, may be necessary.

SCR has been extensively employed in Japan on gas-fired and oil-fired industrial and utility boilers.

III. COST-EFFECTIVENESS

Flue-gas recirculation and ammonia injection are probably the most universally applicable methods for reducing NOx emissions from industrial, institutional, and commercial boilers, and process heaters. The unit cost of NOx emission reduction with FGR ranges from $1600 to $7800 per ton at 50 percent capacity factors. The unit cost of NOx emission reduction with ammonia injection ranges from $1500 to $6000 per ton at 50 percent capacity factors. Low-NOx burners are generally less expensive, and SCR is generally more expensive, than these methods. The ranges are reflective that unit costs generally increase with decreasing equipment size. Furthermore, unit costs increase rapidly with decreasing capacity factors below 25 percent. Table 4 presents a summary of cost-effectiveness ranges for the different technologies.

Table 4

Cost-Effectiveness of Selected NOx Emission Control Technologies

	Annual Capacity Factor	Unit Size Range (MMBtu/hr)	NOx Emission Reduction Cost-Effectiveness Range (1986$ thousand/ton NOx)
Low-NOx Burners	10%		2.3 to 27
	50%	3.5 to 150	0.5 to 6.4
	90%		0.3 to 4.0
Flue Gas Recirculation	10%		6.8 to 29
	50%	3.5 to 350	1.6 to 6.8
	90%		1.0 to 3.7
Selective Noncatalytic Reduction	10%		2.3 to 20
	50%	50 to 375	1.5 to 6.0
	90%		1.3 to 3.8
Selective Catalytic Reduction	10%		24 to 66
	50%	50 to 350	6.0 to 14
	90%		4.0 to 9.0

Reasonably available control technology (RACT) requirements can be met with either FGR or ammonia injection. However, for oil-firing, switching to a lower nitrogen-content fuel may be required. FGR is ineffective at reducing NOx formation originating from fuel nitrogen, and the absolute amount of NOx passing through ammonia injection systems increases directly with the amount entering. Where applicable, low-NOx burners may be more effective at reducing emissions when firing with high-nitrogen fuel.

Best available retrofit control technology (BARCT) requirements for gas-firing may be met by installing new burners with either FGR or ammonia injection. However, both methods, or SCR, may be necessary for up to twice the cost.

IV. IMPACTS

A. Economic

The potential economic impacts of this determination are the capital cost of emission control equipment and the increased operating cost associated with emission control equipment. If combustion equipment is operated with lower excess air after, or instead of, retrofitting control equipment; there will be a cost benefit due to increased thermal efficiency.

B. Air Quality

The most significant impact of this determination is the decrease in NOx emissions and resultant decrease in atmospheric ozone and PM10 formation. Other potential impacts include ammonia slip from SNCR and SCR systems and ammonia leakage from storage and handling systems, which will result in emissions of ammonia to the atmosphere. Ammonia emissions will increase the formation of PM10 in the atmosphere.

C. Hazards

Ammonia is a toxic, highly reactive compound and its use, storage, and transport can be hazardous, especially in the case of worker exposure to highly concentrated ammonia vapor or contact with liquid ammonia. Occupational Safety and Health Administration (OSHA) regulations specify the methods for the use, storage, and transport of ammonia. These regulations were developed to reduce the hazards that could occur when handling ammonia.

The spent catalyst materials from the use of SCR commonly contain small amounts of hazardous materials, including vanadium pentoxide. This compound is toxic if inhaled. A majority of catalysts used in California are now reclaimed and recycled by the manufacturer, so that their disposal should pose no significant environmental impacts. For those facilities that do not recycle their catalysts, the spent material would have to be deposited in a Class I landfill. The only operational Class I disposal site in California is located in Kings County.

D. Energy

Additional fan energy will be required to operate FGR, SNCR, and SCR systems. All of the systems require additional mass flows and gas velocities, which will increase flow losses through the furnaces and downstream passages. The FGR ducting and SCR reactor are additional flow impedances.

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POS

AMOCO LS SUPER D

Suppl

Salt Lake Cit

Amoco Oil Company

Product Manufactured At: Salt Lake City

TEST METHOD	SPECIFICATIONS	NOTES	SALT LAKE CITY (2)
ACM 22.02	Alkalinity		Record
Visual	Appearance	(a)(g)	Clear and bright at 70°F or shipping tank temp.
D482	Ash		MAT 0.01%
D524	Carbon Residue on 10% Btms., Ramo		MAT 0.35%
D976	Cetane Index		MLT 45.0
D613	Cetane Number		MLT 50.0
D1500	Color, ASTM	(h)	Record
D130	Corrosion, Cu Strip, 3 Hrs at 122°F		MOT 3
D86	Distillation:	(e)	
	10% Recovery		Record
	50% Recovery		Record
	90% Recovery		540-640°F
	End Point		MAT 690°F
ACM 18.07	Filterability Index		Record
D56	Flash, TCC	(b)	MLT 125°F
D287	Gravity		Record
D2622	Sulfur: Total		MAT 0.05W%
D3227	Sulfur: Mercaptan Number		No spec
D445	Viscosity, CS at 100°F		1.9-4.1
ACM 18.17	Stability: Haze Pad		Record
D1796	Water and Sediment	(f)	MAT 0.05%
Dosage	Additive, Corrosion Inhibitor	(d)	2 ptb
Dosage	Additive, Pour Depressant		See PQS Page #2580
Dosage	Additive, Red D-Guard Package (Ethyl Hi-Tec 4242)		40 ptb

TEST METHOD	SEASONAL SPECIFICATIONS For month of receipt at terminals:		SUMMER MAR-SEP	WINTER OCT-FEB
D2624	Conductivity		Report	Report
D2500	Cloud	(c)	MAT +25°F	MAT +6°F
D97	Pour, Depr. or nat.		MAT +20°F	MAT -25°F

NOTES:

(a) Requests for Appearance Waivers must be accompanied by information on haze point or water content.
(b) If Flash above 150°F, Pensky-Martens method may be used.
(c) Based on local elevations (Salt Lake City, 650 mm Hg).
(d) Tretolite Tolad 361 or DuPont FOA 408.
(e) Measurement at room temperature rather than 70°F is adequate.
(f) Water and sediment by D2709 optional.
(g) This fuel must be free of visible evidence of blue dye, particularly the EPA specified dye 1,4-dial anthraquinone, designated for off-road fuels.
(h) Cetane improver (MAT 0.2 vol%) is allowed in order to meet the cetane number.

GENERAL NOTES:

(1) Product must also comply with state legal requirements.
(2) Chevron will supply base fuel.

APPENDIX E:

NOTE

AMOCO FUEL OIL IS AVAILABLE IN THE RICHLAND AREA

U.S. OIL & REFINING FUEL OIL IS NOT AVAILABLE IN THE RICHLAND AREA

AMOCO

Quality Assurance/Technical Service Department

Product Information Sheet

FEBRUARY 1993 PI NO. 200

NITROGEN AND TRACE METALS IN NO. 2 DISTILLATES

Utilities and others have expressed interest in the nitrogen and trace metals levels of distillate products. The interest in fuel bound nitrogen is being generated by new source emission policy and emissions control of older installations. The trace metals concerns are related to the durability of turbine equipment. This PI sheet answers some of the questions and concerns about nitrogen and trace metals in No. 2 distillate fuels.

Nitrogen

Fuel bound nitrogen is important because it contributes to nitrogen oxide emissions which are regulated by the Clean Air Act Amendments (CAAA). As an example, the CAAA of 1977 requires gas turbines larger than 1000 hp to have nitrogen oxide (NOx) emissions as low as 75 ppm maximum for turbines located in metropolitan areas. Further, the CAAA of 1990, Title I and Title IV, requires that reasonably available NOx control technology be applied to gas turbines in ozone non-attainment areas (the northeast and Chicago/Milwaukee within our marketing area) and that specific low NOx technology be used for acid rain control. In addition, EPA has established a working group which is charged with looking for further NOx reductions from stationary sources. Finally, some state regulations are even more severe than those imposed by the federal EPA.

In gas turbine and burner units, NOx is generated from both atmospheric and fuel bound nitrogen. The atmospheric nitrogen and oxygen combine in combustion air and form what is commonly called thermal NOx. Thermal NOx formation is very sensitive to local flame temperature and somewhat less sensitive to oxygen concentration. Fuel bound nitrogen when combined with oxygen in combustion air is called fuel NOx. Fuel NOx formation is strongly dependent on the fuel's nitrogen content and air/fuel mixing and to a lesser extent on oxygen concentration. A rule of thumb estimate for the effect of fuel bound nitrogen is 25 ppm of NOx per 1000 ppm nitrogen.

Turbine and burner manufacturers can reduce thermal NOx emissions, designing units which control air/fuel ratio and mixing, as well as combustion air. In addition, many manufacturers specify fuel bound nitrogen limits for warranted NOx performance guarantees. One burner manufacturer asks that nitrogen be limited to 6000 ppm in heavy oil, while a major turbine manufacturer guarantees performance with No. 2 fuels at 150 ppm nitrogen or lower. Further, the use of low nitrogen fuels is a part of NOx control strategy at some existing facilities.

In the fuel industry, marketers do not typically specify nitrogen limits, nor do they typically measure or record fuel nitrogen levels. The limited data available shows the nitrogen level in No. 2 distillates ranges from about 10 ppm to as high as 400 ppm. Consequently, using the rule of thumb introduced above, fuel bound nitrogen can contribute up to 10 ppm of NOx emissions. One recent survey of industry No. 2 diesel/gas turbine fuels at 12 locations within our marketing area showed only five to have samples below 150 ppm, while two were in excess of 300 ppm. Heavier distillates and distillates with synthetic components derived from coal, shale or tar sands tend to have higher nitrogen levels. Residual oils can have nitrogen levels in the 1000s of ppm.

Though nitrogen bound in aromatic compounds is extremely hard to remove, the processing that removes sulfur from distillates also tends to remove nitrogen. Beginning in October of 1993, on-highway (0.05 wt% sulfur) diesel fuels will likely contain low levels of fuel bound nitrogen compared to high sulfur off-highway fuels.

Trace Metals

While the specification of nitrogen levels is driven by environmental concerns, trace metals including sodium, potassium, vanadium, calcium, and lead are driven by economic considerations, specifically gas turbine durability.

Trace levels of sodium, potassium, and vanadium combine to form some extremely corrosive compounds at turbine inlet temperatures about 1200°F eroding turbine blades. Calcium, however, is not a problem from a corrosion standpoint and may, in fact, inhibit the corrosive activity of vanadium, but it forms a hard deposit on the turbine blades that is not easily removed. These deposits can reduce performance and upset the balance of the turbine. Trace levels of lead have commonly been specified because it tends to reduce the effectiveness of additives sometimes used to control vanadium corrosion. Lead is rarely found in crude oil, and the common source had been refinery contamination, it may no longer be an issue with EPA restrictions on the lead content of gasoline.

As with nitrogen, trace metals are not typically specified or measured by the fuel industry. The appendix of the ASTM Standard Specification for Gas Turbine Fuel Oils (ASTM D-2880) suggests maximum limits of 0.5 ppm by weight for vanadium, calcium, lead, and sodium plus potassium. Our recent survey of industry No. 2 fuels at 12 locations noted above found that all met the suggested ASTM trace metal levels recommended for satisfactory service.

U. S. Oil & Refining Co.

3001 Marshall Avenue, Tacoma, Washington, 98421 (206) 383-1651

Diesel #2

Tests	Specifications Min.	Max.
Color, ASTM		1.5
Flash Point	52° C (126° F)	
Distillation - 90% recovered	282° C (540° F)	338° C (640° F)
Pour Point		
Summer[1]		-12° C (10° F)
Winter[2]		-18° C (0° F)
Cloud Point		
Summer[1]		-1° C (30° F)
Winter[2]		-10° C (14° F)
Haze Point	Clear and Bright @ ambient temperature	
Doctor Test		Negative[3]
Corrosion, Copper Strip		1B
Sulfur, mass %		0.050[4]
Cetane Index	40	
Viscosity @ 40° C (104° F) mm²/S (cSt)	1.9	4.1
Ash, mass %		0.01
Carbon - Residue on 10 % distillation residue % mass		0.35
B.S. & W., Volume %		0.05
Conductivity, pa/m	50	

Meets or Exceeds:
ASTM D975
Fed. Specification VV-7-800-C Fuel Oil, Diesel, Grade DF-2

1) Summer - March 1 - October 31
2) Winter - November 1 - February 29
3) If Doctor test is positive then mercaptan sulfur must be less than 30 PPM
4) Sulfur test is ASTM 4294

APPENDIX F:

Cleaver-Brooks
PERFORMANCE PROVEN WORLDWIDE

March 4, 1997

Mr. Tim W. Sonnichsen, P.E.
Carnot Northwest Office
P.O. Box 2932
Woodinville, WA 98072

Subj. Hanford Project
Cleaver-Brooks Boilers

Dear Tim:

Following a critical review of all data available, Cleaver-Brooks guarantees the emission levels, per the table below, for boilers rated 5,000,000 Btu input and larger for the Hanford project.

The emission levels are guaranteed based on testing at steady state operation and at the high fire rate. The units must be properly warmed-up to reach normal operating temperatures throughout the unit. Since the maximum potential emission levels occur at full Btu input rating, the guarantee is based on high fire performance.

Emission Level		
Pollutant	Natural Gas	No. 2 Oil
VOC PPM, Dry, Corrected to 3% O_2	30	30
NO_x PPM, Dry, Corrected to 3% O_2	30	115
CO PPM, Dry, Corrected to 3% O_2	300	90
PM, lbs/MMBtu	0.012	0.011

Note: 1. NO_x level on No. 2 oil is based on a maximum fuel bound nitrogen content of 0.04% by weight.

2. Particulate material level on No. 2 oil is based on a maximum sulfur content of 0.05% by weight and maximum ash content of 0.01% by weight.

3. Cleaver-Brooks classifies all particulate matter from natural gas and No. 2 oil as PM_{10}.

4. These emission levels do not include any fugitive or background emissions at the jobsite.

Questions regarding the table and other comments may be directed to my attention.

Regards,

Ron Wildasin

Ron Wildasin
RW.sew
rwfmfrd

cc: Glen Waldenberg, Cole Industrial
Bill Kelly, Johnson Controls
Mark Ziolkowski

P. O. Box 421 Milwaukee, WI 53201 • Telephone (414) 359-0600

APPENDIX G:

VENTURA COUNTY APCD
AB 2588 COMBUSTION EMISSION FACTORS

Emission factors for combustion of natural gas and diesel fuel were developed for use in AB 2588 emission inventory reports in 1990 and updated in 1991. These factors have been updated again based on additional source testing which has been performed under AB 2588. These emission factors are to be used where source testing or fuel analysis are not required by the AB 2588 Criteria and Guidelines Regulations, Appendix D. The factors are applicable to all non-utility combustion sources and are divided into external combustion sources (boilers, heaters, flares) and internal combustion sources (engines, turbines). Natural gas combustion factors are further divided into a number of sub-categories, based on equipment size and type.

If better source specific data such as manufacturer's data, source tests, or fuel analysis is available, it should be used rather than these emission factors.

Natural Gas Combustion Factors

Natural gas combustion factors were developed for listed substances identified by the California Air Resources Board (CARB) as significant components of natural gas combustion emissions (1).

Internal Combustion

	engine <1000 hp	engine >1000 hp	turbine
Pollutant	Emissions (lb/MMcf)		
benzene	3.2570	3.9084	0.01906
formaldehyde	32.4963	38.9956	0.1730
PAH's (including naphthalene)	0.1964	0.1964	0.00115
naphthalene	0.1785	0.1785	0.00093
acetaldehyde	0.9440	1.1328	0.0173
acrolein	0.3783	0.4540	0.0017
propylene	16.2259	19.4711	0.1824
toluene	1.1145	1.3374	0.1282
xylenes	0.4048	0.4858	0.0298

All emission factors for internal combustion engines were based on source testing performed under the AB 2588 program (6).

For turbines, the PAH, naphthalene, benzene, toluene, xylenes, and propylene emission factors were also based on source testing (16), (17), (18). Turbine emission factors for acrolein and acetaldehyde are based on formaldehyde source test results and a CARB assumption that, as an estimate, it can be assumed that acetaldehyde emissions are an order of magnitude less than formaldehyde and acrolein emissions are an order of magnitude less than acetaldehyde (14).

External Combustion

	<10 MMBTUh	10-100 MMBTUh	>100 MMBTUh	flare
Pollutant	Emissions (lb/MMcf)			
benzene	0.0185	0.0133	0.0040	0.1152
formaldehyde	0.0409	0.0296	0.0087	1.1376
PAH's (including naphthalene)	0.1964	0.1964	0.1964	0.0273
naphthalene	0.1785	0.1785	0.1785	NA
acetaldehyde	0.0353	0.0258	0.0073	0.1138
acrolein	0.0131	0.0110	0.0022	0.0114
propylene	0.2737	0.1984	0.0582	2.0160
toluene	0.0059	0.0043	0.0013	0.0576
xylenes	0.0022	0.0016	0.0005	0.0576

NA - Not available. Due to lack of information, it must be assumed that all PAH's from this source are carcinogenic (no naphthalene).

External combustion equipment includes boilers, heaters, and steam generators.

The benzene and formaldehyde emission factors for external combustion equipment, with the exception of flares, were based on the results of source tests performed on two units rated at between 10 and 100 million BTU per hour (2) (5). The PAH and naphthalene factors were assumed to be the same for external combustion devices other than flares as for internal combustion engines.

Attachment 4

The attached spreadsheet summary has the ESPC Emission calculations to meet NOC and annual report requirements. It includes monthly emission calculations (January-April, 1998) for the five diesel-fired boillers (three in 200W, two in 200E) that are greater than 10 MMBTU/hr, which are subject to New Source Performance Standards, 40 CFR 60, Subpart Dc. This preliminary spreadsheet does not include emissions from natural gas-fired boilers or from diesel-fired boilers that are less than 10 MMBTU/hr.

Potential emissions for the site from ESPC boiler operations are based on continuous operation (24 hrs/day, 365 days/yr) for all boilers, gas and diesel, operating at full capacity. Fuel usage was based on HP rating of boilers, without considering efficiency. These numbers are comparable to those found in the Notice of Construction application, which probably did take boiler efficiecy in consideration. Based on these emission potentials, the Hanford site is still a major source, subject to Title V requirements.

conoco

Geroge Saenz
R.H. Smith Distributing
(509)-882-5755

January 21, 1998

George,

I am writing in response to your request for data concerning diesel at the Conoco Spokane, Washington terminal.

I looked at data from the Billings, Montana refinery for the last year. The data set represents over 120 million gallons. Hopefully it will meet your needs.

SULFUR CONTENT

All of the burner fuel supplied to you is low sulfur diesel, dyed for tax exemption. The maximum sulfur level specification is .05% wt. Data from actual production showed a low of 0.011% and a high of 0.044%. The average was 0.030%.

HEAT CONTENT

The calculated gross heat of combustion ranged from a low of 138,000 BTU's per gallon to a high of 140,000 BTU's per gallon; the average was 139,000 BTU's per gallon.

If I can be of further assistance, please call.

Best regards,

Mitch Oliver
Director of Product Quality-Rockies

Printed on recycled paper

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2	Criteria Pollutant	Total 1997	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total 1998
3															
4	Total Diesel Emissions														
5															
6	NOx (tons)	0.30	0.72	0.61	0.54	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.23
7	SO2 (tons)	0.10	0.24	0.21	0.18	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76
8	CO (tons)	0.14	0.34	0.29	0.25	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.05
9	PM10 (tons)	0.02	0.05	0.04	0.04	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
10	Total PM (tons)	0.03	0.07	0.06	0.05	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22
11	VOC's (tons)	0.03	0.06	0.05	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19
12	Lead (lbs)	0.03	0.09	0.07	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26
13															
14	Total Natural Gas Emissions														
15															
16	NOx (tons)	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	SO2 (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	CO (tons)	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	PM10 (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Total PM (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	VOC's (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Lead (lbs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23															
24	Subtotal 200 East Emissions														
25															
26	NOx (kg)	103.18	66.64	50.86	42.46	22.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	182.07
27	SO2 (kg)	33.58	22.66	17.29	14.44	7.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.90
28	CO (kg)	46.74	31.54	24.08	20.10	10.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.18
29	PM10 (kg)	7.24	4.89	3.73	3.11	1.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.35
30	Total PM (kg)	9.88	6.66	5.09	4.25	2.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.21
31	VOC's (kg)	8.56	5.78	4.41	3.68	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.78
32	Lead (kg)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
33															
34	Subtotal 200 West Emissions														
35															
36	NOx (kg)	166.85	586.82	503.04	445.52	304.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1839.89
37	SO2 (kg)	56.73	199.52	171.03	151.48	103.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	625.56
38	CO (kg)	78.98	277.76	238.10	210.88	144.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	870.88
39	PM10 (kg)	12.24	43.03	36.89	32.67	22.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	134.93
40	Total PM (kg)	16.69	58.68	50.30	44.55	30.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	183.99
41	VOC's (kg)	14.46	50.86	43.60	38.61	26.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	159.46
42	Lead (kg)	0.01	0.03	0.03	0.03	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11
43															
44	Total 300 Area Emissions														
45															
46	NOx (kg)	1.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	SO2 (kg)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	CO (kg)	4.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	PM10 (kg)	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Total PM (kg)	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	VOC's (kg)	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Lead (kg)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53															
54															
55															
56	Potential Diesel Emissions														
57															
58	NOx (tons)	0.00	9.81	8.86	9.81	9.49	9.81	9.49	9.81	9.81	9.49	9.81	9.81	9.81	115.77
59	SO2 (tons)	0.00	3.31	2.99	3.31	3.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.80
60	CO (tons)	0.00	4.60	4.16	4.60	4.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.82
61	PM10 (tons)	0.00	0.71	0.64	0.71	0.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.76
62	Total PM (tons)	0.00	0.97	0.88	0.97	0.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.77
63	VOC's (tons)	0.00	0.84	0.76	0.84	0.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.26
64	Lead (lbs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65															
66	Potential Natural Gas Emissions														
67															
68	NOx (tons)	0.00	2.77	2.50	2.77	2.68	2.77	2.68	2.77	2.77	2.68	2.77	2.68	2.77	32.59
69	SO2 (tons)	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.35
70	CO (tons)	0.00	11.10	10.02	11.10	10.74	11.10	10.74	11.10	11.10	10.74	11.10	10.74	11.10	130.68
71	PM10 (tons)	0.00	0.59	0.53	0.59	0.57	0.59	0.57	0.59	0.59	0.57	0.59	0.57	0.59	6.97
72	Total PM (tons)	0.00	0.59	0.53	0.59	0.57	0.59	0.57	0.59	0.59	0.57	0.59	0.57	0.59	6.97
73	VOC's (tons)	0.00	0.64	0.58	0.64	0.62	0.64	0.62	0.64	0.64	0.62	0.64	0.62	0.64	7.55
74	Lead (lbs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

242A BLR001

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 10:17:34

LIGHT OIL

O2 % 4.0
CO ppmn 6
Prs NOT FITTED
EFF % (G) 86.3
XAIR % 23
CO2 % 12.5

NO ppmn ... 69
NO2 ppmn 0
NOx ppmn ... 69
SO2 ppmn 7
REF. %O2 ... 3.0

NETT .. F 313.5
FLUE .. F 367.1
INLT NOT FITTED
AMBIENT F 53.6

242A BLR002

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 10:04:57

LIGHT OIL

O2 % 3.5
CO ppmn ... 11
Prs NOT FITTED
EFF % (G) 88.7
XAIR % 20
CO2 % 12.9

NO ppmn ... 60
NO2 ppmn 0
NOx ppmn ... 60
SO2 ppmn 6
REF. %O2 ... 3.0

NETT .. F 217.6
FLUE .. F 266.3
INLT NOT FITTED
AMBIENT F 48.7

242A BLR003

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 09:59:48

LIGHT OIL

O2 % 3.4
CO ppmn 6
Prs NOT FITTED
EFF % (G) 88.9
XAIR % 19
CO2 % 13.0

NO ppmn ... 78
NO2 ppmn 0
NOx ppmn ... 78
SO2 ppmn 5
REF. %O2 ... 3.0

NETT .. F 208.8
FLUE .. F 255.9
INLT NOT FITTED
AMBIENT F 47.1

BLR001 234Z

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:47:05

LIGHT OIL

O2 % 4.3
CO ppmn ... 37
Prs NOT FITTED
EFF % (G) 86.6
XAIR % 26
CO2 % 12.3

NO ppmn ... 84
NO2 ppmn 0
NOx ppmn ... 84
SO2 ppmn ... 15
REF. %O2 ... 3.0

NETT .. F 295.0
FLUE .. F 355.4
INLT NOT FITTED
AMBIENT F 60.4

234Z BLR002

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:38:16

LIGHT OIL

O2 % 4.3
CO ppmn ... 24
Prs NOT FITTED
EFF % (G) 86.4
XAIR % 25
CO2 % 12.3

NO ppmn ... 85
NO2 ppmn 0
NOx ppmn ... 85
SO2 ppmn ... 12
REF. %O2 ... 3.0

NETT .. F 302.2
FLUE .. F 361.5
INLT NOT FITTED
AMBIENT F 59.3

234Z BLR003

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:26:51

LIGHT OIL

O2 % 3.9
CO ppmn ... 21
Prs NOT FITTED
EFF % (G) 86.9
XAIR % 23
CO2 % 12.6

NO ppmn ... 85
NO2 ppmn 0
NOx ppmn ... 85
SO2 ppmn ... 13
REF. %O2 ... 3.0

NETT .. F 291.6
FLUE .. F 350.4
INLT NOT FITTED
AMBIENT F 58.6

MOBIL STEAM PLANT

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 12:02:20

LIGHT OIL

O2 % 4.0
CO ppmn ... 22
Prs NOT FITTED
EFF % (G) 88.0
XAIR % 23
CO2 % 12.5

NO ppmn ... 95
NO2 ppmn 0
NOx ppmn ... 95
SO2 ppmn 1
REF. %O2 ... 3.0

NETT .. F 239.5
FLUE .. F 299.6
INLT NOT FITTED
AMBIENT F 60.0

283-W

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 12:49:55

LIGHT OIL

O2 % 4.1
CO PPMN 5
Prs NOT FITTED
EFF % (G) 88.4
XAIR % 23
CO2 % 12.1

NO PPMN ... 71
NO2 PPMN 0
NOx PPMN ... 71
SO2 PPMN 2
REF. %O2 ... 3.0

NETT .. F 221.4
FLUE .. F 277.7
INLT NOT FITTED
AMBIENT F 56.3

272-BA

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 12:10:49

LIGHT OIL

O2 % 3.3
CO PPMN 2
Prs NOT FITTED
EFF % (G) 87.7
XAIR % 22
CO2 % 12.7

NO PPMN ... 80
NO2 PPMN 0
NOx PPMN ... 80
SO2 PPMN 7
REF. %O2 ... 3.0

NETT .. F 259.8
FLUE .. F 318.5
INLT NOT FITTED
AMBIENT F 59.3

225E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 11:34:59

LIGHT OIL

O2 % 3.9
CO PPMN 4
Prs NOT FITTED
EFF % (G) 87.1
XAIR % 23
CO2 % 12.5

NO PPMN ... 71
NO2 PPMN 0
NOx PPMN ... 71
SO2 PPMN 9
REF. %O2 ... 3.0

NETT .. F 278.4
FLUE .. F 344.3
INLT NOT FITTED
AMBIENT F 65.8

373E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 10:32:57

LIGHT OIL

O2 % 4.6
CO PPM 4
Prs NOT FITTED
EFF % (G) 87.9
XAIR % 28
CO2 % 12.0

NO PPM ... 196
NO2 PPM 0
NOx PPM ... 196
SO2 PPM 7

NETT .. F 239.2
FLUE .. F 299.3
INLT NOT FITTED
AMBIENT F 60.0

200CL

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 13:50:01

LIGHT OIL

O2 % 4.1
CO PPM 4
Prs NOT FITTED
EFF % (G) 87.8
XAIR % 24
CO2 % 12.5

NO PPM ... 210
NO2 PPM 0
NOx PPM ... 210
SO2 PPM 4

NETT .. F 247.5
FLUE .. F 307.2
INLT NOT FITTED
AMBIENT F 59.7

283E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 09:50:01

LIGHT OIL

O2 % 3.6
CO PPMN ... 10
Prs NOT FITTED
EFF % (G) 88.1
XAIR % 20
CO2 % 12.8

NO PPMN ... 73
NO2 PPMN 0
NOx PPMN ... 73
SO2 PPMN ... 11
REF. %O2 ... 3.0

NETT .. F 243.8
FLUE .. F 297.1
INLT NOT FITTED
AMBIENT F 53.7

222S BUR 002

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 13:55:11

LIGHT OIL

O2 % 3.3
CO PPMN 8
Prs NOT FITTED
EFF % (G) 87.3
XAIR % 19
CO2 % 13.0

NO PPMN ... 67
NO2 PPMN 0
NOx PPMN ... 67
SO2 PPMN 4
REF. %O2 ... 3.0

NETT .. F 279.1
FLUE .. F 340.5
INLT NOT FITTED
AMBIENT F 61.3

2225 BUR 001

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 14:06:13

LIGHT OIL

O2 % 4.3
CO PPMN 5
Prs NOT FITTED
EFF % (G) 87.5
XAIR % 25
CO2 % 12.3

NO PPMN ... 56
NO2 PPMN 0
NOx PPMN ... 56
SO2 PPMN 3
REF. %O2 ... 3.0

NETT .. F 262.9
FLUE .. F 324.0
INLT NOT FITTED
AMBIENT F 61.8

Draft spread sheet Emission Calculations (Fuel Use)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1																		
2	Boiler Annex		Fuel	Boiler HP	Total 1997	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total 1998
3	200CC	Boiler 1	diesel (gal)	80	1292													0
4	225-B	Boiler 1	diesel (gal)	150	3773													0
5	275-E	Boiler 1	diesel (gal)	80	1048													0
6	272-W	Boiler 1	diesel (gal)	250	3317													0
7	222-2	Boiler 1	diesel (gal)	200	448													0
8		Boiler 2	diesel (gal)	200	7519													0
9	283-W	Boiler 1	diesel (gal)	200	1440													0
10	283-E	Boiler 1	diesel (gal)	200	1661													0
11	234-5Z	Boiler 1	diesel (gal)	350	1549													0
12		Boiler 2	diesel (gal)	350	2580													0
13		Boiler 3	diesel (gal)	350	789													0
14	242-A	Boiler 1	diesel (gal)	200	1730													0
15		Boiler 2	diesel (gal)	700	900													0
16		Boiler 3	diesel (gal)	700	38													0
17	305	Boiler 1	gas (cu. ft.)	40	0.00E+00													0.00E+00
18	306-E	Boiler 1	gas (cu. ft.)	150	0.00E+00													0.00E+00
19	318	Boiler 1	gas (cu. ft.)	30	0.00E+00													0.00E+00
20	320	Boiler 1	gas (cu. ft.)	100	0.00E+00													0.00E+00
21		Boiler 2	gas (cu. ft.)	100	0.00E+00													0.00E+00
22	323	Boiler 1	gas (cu. ft.)	50	0.00E+00													0.00E+00
23	324	Boiler 1	gas (cu. ft.)	300	0.00E+00													0.00E+00
24		Boiler 2	gas (cu. ft.)	300	0.00E+00													0.00E+00
25	325	Boiler 1	gas (cu. ft.)	125	0.00E+00													0.00E+00
26		Boiler 2	gas (cu. ft.)	125	0.00E+00													0.00E+00
27	326	Boiler 1	gas (cu. ft.)	100	0.00E+00													0.00E+00
28		Boiler 2	gas (cu. ft.)	100	0.00E+00													0.00E+00
29	327	Boiler 1	gas (cu. ft.)	200	0.00E+00													0.00E+00
30	328	Boiler 1	gas (cu. ft.)	30	0.00E+00													0.00E+00
31	329	Boiler 1	gas (cu. ft.)	50	0.00E+00													0.00E+00
32		Boiler 2	gas (cu. ft.)	50	0.00E+00													0.00E+00
33		Boiler 3	gas (cu. ft.)	50	0.00E+00													0.00E+00
34		Boiler 4	gas (cu. ft.)	50	0.00E+00													0.00E+00
35	331	Boiler 1	gas (cu. ft.)	300	0.00E+00													0.00E+00
36		Boiler 2	gas (cu. ft.)	300	0.00E+00													0.00E+00
37	337-B	Boiler 1	gas (cu. ft.)	60	0.00E+00													0.00E+00
38		Boiler 2	gas (cu. ft.)	60	0.00E+00													0.00E+00
39	382-A-D	Boiler 1	gas (cu. ft.)	200	0.00E+00													0.00E+00
40	3705	Boiler 1	gas (cu. ft.)	15	0.00E+00													0.00E+00
41	3706	Boiler 1	gas (cu. ft.)	80	0.00E+00													0.00E+00
42	3717	Boiler 1	gas (cu. ft.)	80	0.00E+00													0.00E+00
43	3717B	Boiler 1	gas (cu. ft.)	80	0.00E+00													0.00E+00
44	3709A	Boiler 1	gas (cu. ft.)	15	0.00E+00													0.00E+00
45	3720	Boiler 1	gas (cu. ft.)	125	0.00E+00													0.00E+00
46	3745	Boiler 1	gas (cu. ft.)	15	0.00E+00													0.00E+00
47																		
48	Subtotal > 5 MMBTU		diesel (gal)		25744	0	0	0	0	0	0	0	0	0	0	0	0	0
49	Subtotal < 5 MMBTU		diesel (gal)		2340	0	0	0	0	0	0	0	0	0	0	0	0	0
50	Subtotal > 5 MMBTU		gas (cu. ft.)		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
51	Subtotal < 5 MMBTU		gas (cu. ft.)		4.10E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
52																		
53	Subtotal 200 East Area				10442	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Subtotal 200 West Area				17642	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Subtotal 300 Area				4.10E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Draft spread sheet Emission Factors

	A	B	C	D	E
1					
2	Emission Factors used in Notice of Construction (lb/MMBTU)				
3					
4					
5	Criteria Pollutant	Diesel-fired > 5 MMBTU/hr	Diesel-fired < 5 MMBTU/hr	Natural gas-fired > 5 MMBTU/hr	Natural gas-fired < 5 MMBTU/hr
6					
7	NOx	1.50E-01	1.80E-01	3.70E-02	1.00E-01
8	SO2	5.10E-02	5.10E-02	6.00E-04	6.00E-04
9	CO	7.10E-02	7.10E-02	2.25E-01	2.25E-01
10	PM10	1.10E-02	1.10E-02	1.20E-02	1.20E-02
11	Total PM	1.50E-02	1.50E-02	1.20E-02	1.20E-02
12	VOC's	1.30E-02	1.30E-02	1.30E-02	1.30E-02
13	Lead	8.90E-06	8.90E-06	0.00E+00	0.00E+00

Draft spread sheet Emission Calculations

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2	Criteria Pollutant	Total 1997	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total 1998
3															
4	Total Diesel Emissions														
5															
6	NOx (tons)	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	SO2 (tons)	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	CO (tons)	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	PM10 (tons)	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Total PM (tons)	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	VOC's (tons)	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	Lead (lbs)	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13															
14	Total Natural Gas Emissions														
15															
16	NOx (tons)	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	SO2 (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	CO (tons)	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	PM10 (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Total PM (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	VOC's (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Lead (lbs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23															
24	Subtotal 200 East Emissions														
25															
26	NOx (kg)	103.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	SO2 (kg)	33.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	CO (kg)	46.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	PM10 (kg)	7.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Total PM (kg)	9.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	VOC's (kg)	8.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Lead (kg)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33															
34	Subtotal 200 West Emissions														
35															
36	NOx (kg)	166.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	SO2 (kg)	56.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	CO (kg)	78.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	PM10 (kg)	12.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	Total PM (kg)	16.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	VOC's (kg)	14.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Lead (kg)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43															
44	Total 300 Area Emissions														
45															
46	NOx (kg)	1.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	SO2 (kg)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	CO (kg)	4.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	PM10 (kg)	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Total PM (kg)	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	VOC's (kg)	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Lead (kg)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Washington State Department of Health

News Release

For Immediate Release: May 13, 1998 (98-41)

Contacts: Al Conklin, Division of Radiation Protection (360) 236-3261
Steve Kelso, Office of Communications (360) 586-4002

Hanford given notice for violation of radioactive emission regulations

OLYMPIA — Today, the Washington State Department of Health's Division of Radiation Protection issued a Notice of Violation to the U.S. Department of Energy for violating radioactive air emissions regulations governing the potential release, monitoring, and control of airborne radioactivity.

The Department of Health has federal and state enforcement authority for ensuring that the public is not affected or harmed by the release of radioactivity to the air, especially at the Hanford Site near Richland, where significant releases occurred in the past.

The violation occurred April 14-17, when the Department of Energy processed obsolete nuclear weapons components in a furnace in what is called the "300 Area" of the Hanford Site, next to the Columbia River. "The violation has two parts," said Al Conklin, manager of the Department of Health's Air Emissions and Defense Waste program. "First of all, this furnace is only permitted to treat small quantities of buried waste – not weapons components. Secondly, the Department of Energy decided to turn off samplers that would have measured the amount of radiation going out the stack of the furnace."

According to Conklin, the weapons components contained tritium, a radioactive hydrogen isotope that is used to boost the power of nuclear weapons. "It appears that the total amount of tritium released was small," Conklin said, "and that there was no threat to public health."

Conklin, who has a security clearance, has reviewed the classified data on the amount of tritium contained in the weapons components – information that existed before the violation and which is not dependent on operation of the furnace stack samplers. He was able to verify that the release was less than the 20 curies permitted by the Department of Health.

"To justify turning off the samplers," Conklin said, "the Department of Energy claimed the information was classified for security reasons. They did not discuss the issue with us in advance. This is an important part of the violation. If we allowed this to go unchallenged, it would establish a dangerous precedent for behavior that is reminiscent of Hanford's past. Security classification is no justification for not collecting data on stack emissions. It was practices like this in the past that resulted in significant distrust of the Department of Energy by the public and the need to calculate historical doses that the public might have received from these releases."

-More-

The Department of Health's Hanford Health Information Network is currently disseminating information to the public on those past releases of radioactivity, which occurred in the 1940s and '50s and primarily involved radioactive iodine, which is much more dangerous than tritium.

As part of the Notice of Violation, the Department of Health issued compliance orders requiring the Department of Energy to evaluate all their permits to assure there are no further discrepancies, and requiring them to obtain the proper permit for further work in the furnace, and to operate the tritium sampler continuously. Conklin said, "While the Department of Health has the authority to issue fines, we will reserve that option as a last resort to be exercised only if the Department of Energy does not meet the conditions of the compliance order."

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AIR 98-501

STATE OF WASHINGTON
DEPARTMENT OF HEALTH
DIVISION OF RADIATION PROTECTION
7171 Cleanwater Lane, Bldg. 5 • P.O. Box 47827 • Olympia, Washington 98504-7827
TDD Relay 1-800-833-6388

NOTICE OF VIOLATION

May 13, 1998

Mr. James E. Rasmussen, Director
U. S. Department of Energy
Environmental Assurance,
Permits and Policy Division
Richland Operations Office
P. O. Box 550 MSIN A 5-15
Richland, Washington 99352

Dear Mr. Rasmussen:

This letter constitutes a Notice of Violation under Revised Code of Washington (RCW) 70.94.332 and Washington Administrative Code (WAC) 246-247-100. This letter also constitutes a Notice of Correction under Chapter 43.05 RCW. The Department of Health (DOH), Division of Radiation Protection finds the U.S. Department of Energy in violation of radioactive air emissions regulations in the operation of the Plasma Arc Furnace in the 324 Building Waste Technology Engineering Laboratory, located in the 300 Area of the Hanford Site.

I. FINDINGS

Violation #1: During the running of the Plasma Arc Furnace, the tritium samplers were turned off, violating the requirement for confirmatory sampling to verify low emissions of tritium.

Under 40 CFR § 61.93(b)(2)(ii), a copy of which is enclosed hereto as Enclosure A, continuous sampling is required unless periodic sampling is specifically approved.

DOH has adopted by reference the requirements of 40 CFR Part 61, Subparts H and I, published in the Federal Register on December 18, 1989, pursuant to WAC 246-247-075, a copy of which is enclosed hereto as Enclosure B. WAC 246-247-075(4) further provides that DOH may allow a facility to use alternative monitoring procedures if continuous monitoring is not a feasible or reasonable requirement. WAC 246-247-075(3) provides that the operator of an emission unit with a potential-to-emit of less than 0.1 millirem per year TEDE to the MEI may estimate those radionuclide emissions in lieu of monitoring but DOH may require periodic confirmatory measurements during routine operations to verify low emissions. Methods to implement periodic confirmatory monitoring shall be approved by DOH. Additionally, DOE's Facility Effluent Monitoring Plan (FEMP), established in accordance with 40 CFR Part 61, makes a commitment that the Plasma Arc Furnace stack tritium sampler will operate continuously.

DOE conducted a project to treat neutron generators in the Plasma Arc Furnace during the week of April 13, 1998. DOE shut down the stack tritium sampler for the duration of this project. Although the project was considered "minor" as far as potential emissions were concerned, DOE did not submit a request for approval of periodic confirmatory monitoring to verify low emissions. Confirmatory monitoring was of particular importance because the project was a batch process, indicating that the project was complete in a short period of time, as opposed to a full year. DOH had every expectation that DOE would continue to operate the tritium sampler in accordance with the FEMP or to meet the minimum requirements for periodic confirmatory monitoring. DOE failed to comply with WAC 246-247-075 and 40 CFR Part 61.

<u>Violation #2</u>: The project to treat obsolete nuclear weapons components violated the Notice of Construction for the Plasma Arc Furnace.

Pursuant to WAC 246-247-060(1), a copy of which is enclosed hereto as Enclosure C, for new construction or modification of emission units, the applicant must submit a Notice of Construction containing the information required in WAC 246-247-110, a copy of which is enclosed hereto as Enclosure D. WAC 246-247-110(5) requires a description of the chemical and physical processes upstream of the emissions unit. Under WAC 246-247-110(8), the Notice of Construction must also identify each radionuclide that could contribute greater than ten percent of the potential-to-emit TEDE to the MEI, or greater than 0.1 millirem per year potential-to-emit TEDE to the MEI. For this project, tritium represented 100% of the radionuclides involved.

A Notice of Construction for the Plasma Arc Furnace was approved and the DOE license amended by DOH in July of 1996. A modification was approved and the license amended accordingly in August of 1997. The Notice of Construction was developed "to treat waste from across the DOE complex." The cover letter for the NOC is more specific, stating that the process is to "treat buried waste from across the complex" (highlights added) letter # 96-PCA -149 enclosed. During the week of April 13, 1998, DOE processed obsolete nuclear weapons components containing tritium. These components are not considered buried waste, and, therefore, the processing of these components was not approved by DOH.

DOE failed to disclose the nature and general description of the material to be processed and the consequential change of the radionuclide of concern by batch type (pursuant to WAC 246-247-110(8)) prevented DOH from determining if controls and monitoring were adequate or available to verify and ensure that the source term was as low as promised in the modified license.

See the Press release Conklin was able to verify

While it is understood that the effluent tritium data would have had to be classified, there are mechanisms to accomplish that while still providing the department with sufficient information that tritium limits would not have been exceeded.

II. COMPLIANCE ORDER

1. DOE is ordered to immediately maintain tritium samplers in operation as required under WAC 246-247-075 and 40 CFR Part 61. If DOE determines it appropriate to use confirmatory sampling instead of continuous sampling, DOE must, in accordance with WAC 246-247-075(4), submit a request to perform periodic sampling to DOH and receive approval from DOH prior to conducting periodic rather than continuous sampling.

2. DOE is ordered to modify its Notice of Construction for the Plasma Arc Furnace to fully address controls and monitoring needs in accordance with WAC 246-247-060

and WAC 246-247-110, prior to processing any more material through the furnace. You must allow thirty days for a determination of completeness and sixty days for a full review.

3. DOE is ordered to modify any other approved Notices of Construction in which discrepancies exist between the Notice of Construction and actual work or planned work, in accordance with WAC 246-247-060 and WAC 246-247-110, if not specifically approved by DOH. You must notify the DOH within 60 days of receipt of this NOV of any such discrepancies. We will then negotiate due dates for NOC revisions. These due dates will then be binding.

III. PLACE TO SUBMIT DOCUMENTS AND REQUESTS

All documents required to be submitted to DOH should be sent to Allen W. Conklin at 7171 Cleanwater Lane, Building 5, P. O. Box 47827, Olympia, WA 98504-7827. Questions about compliance with the order should be also be sent to Al Conklin.

A request to extend a time period for good cause may be filed with DOH by sending a written request to Al Conklin at the above address within the time period specified for compliance. Any such request will be reviewed and a written response provided to you within ten (10) days of DOH's receipt of your request.

IV. PENALTIES

Under RCW 70.94.431, DOH is authorized to issue a civil penalty to any person who violates the provisions of Chapter 70.94 RCW or any of the rules in force under Chapter 70.94 RCW. A penalty of up to ten thousand dollars per day per violation may be imposed. If you fail to comply with the compliance order portion of this Notice of Violation, a penalty will be imposed. If you wish to meet with DOH prior to the commencement of formal enforcement action, you may request a meeting within 30 days of your receipt of this NOV. To request a meeting, contact Al Conklin at (360) 236-3261.

V. TECHNICAL ASSISTANCE

Technical assistance services available from DOH may be obtained by calling or writing Al Conklin at the above address or phone number.

DATED this 13 day of May, 1998.

John L. Erickson, Director

Enclosures: A - 40 CFR § 61.93(b)(2)(ii)
B - WAC 246-247-075
C - WAC 246-247-060(1)
D - WAC 246-247-110
DOE Letter # 96-PCA-149

ENCLOSURE A

§61.93 Emission monitoring and test procedures.

(a) To determine compliance with the standard, radionuclide emissions shall be determined and effective dose equivalent values to members of the public calculated using EPA approved sampling procedures, computer models CAP-88 or AIRDOS-PC, or other procedures for which EPA has granted prior approval. DOE facilities for which the maximally exposed individual lives within 3 kilometers of all sources of emissions in the facility, may use EPA's COMPLY model and associated procedures for determining dose for purposes of compliance.

(b) Radionuclide emission rates from point sources (stacks or vents) shall be measured in accordance with the following requirements or other procedures for which EPA has granted prior approval:

(1) Effluent flow rate measurements shall be made using the following methods:

(i) Reference Method 2 of appendix A to part 60 shall be used to determine velocity and volumetric flow rates for stacks and large vents.

(ii) Reference Method 2A of appendix A to part 60 shall be used to measure flow rates through pipes and small vents.

(iii) The frequency of the flow rate measurements shall depend upon the variability of the effluent flow rate. For variable flow rates, continuous or frequent flow rate measurements shall be made. For relatively constant flow rates only periodic measurements are necessary.

(2) Radionuclides shall be directly monitored or extracted, collected and measured using the following methods:

(i) Reference Method 1 of appendix A part 60 shall be used to select monitoring or sampling sites.

(ii) The effluent stream shall be directly monitored continuously with an in-line detector or representative samples of the effluent stream shall be withdrawn continuously from the sampling site following the guidance presented in ANSIN13.1-1969 "Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities" (including the guidance presented in appendix A of ANSIN13.1) (incorporated by reference—see §61.18). The requirements for continuous sampling are applicable to batch processes when the unit is in operation. Periodic sampling (grab samples) may be used only with EPA's prior approval. Such approval may be granted in cases where continuous sampling is not practical and radionuclide emission rates are relatively constant. In such cases, grab samples shall be collected with sufficient frequency so as to provide a representative sample of the emissions.

(iii) Radionuclides shall be collected and measured using procedures based on the principles of measurement described in appendix B, Method 114. Use of methods based on principles of measurement different from those described in appendix B, Method 114 must have prior approval from the Administrator. EPA reserves the right to approve measurement procedures.

(iv) A quality assurance program shall be conducted that meets the performance requirements described in appendix B, Method 114.

(3) When it is impractical to measure the effluent flow rate at an existing source in accordance with the requirements of paragraph (b)(1) of this section or to monitor or sample an effluent stream at an existing source in accordance with the site selection and sample extraction requirements of paragraph (b)(2) of this section, the facility owner or operator may use alternative effluent flow rate measurement procedures or site selection and sample extraction procedures provided that:

ENCLOSURE B.

WAC 246-247-075 Monitoring, testing and quality assurance. (1) All radioactive air emissions monitoring, testing, and quality assurance requirements of 40 CFR 61, Subparts H and I published in the *Federal Register* on December 15, 1989, are adopted by reference, as applicable as specified by the referenced subparts.

(2) Equipment and procedures used for the continuous monitoring of radioactive air emissions shall conform, as applicable, to the guidance contained in ANSI N13.1, ANSI N42.18, ANSI N323, ANSI N317, reference methods 1, 1A, 2, 2A, 2C, 2D, 4, 5, and 17 of 40 CFR Part 60, Appendix A, 40 CFR Part 52, Appendix E, and any other methods approved by the department.

(3) The operator of an emission unit with a potential-to-emit of less than 0.1 mrem/yr TEDE to the MEI may estimate those radionuclide emissions, in lieu of monitoring, in accordance with 40 CFR 61 Appendix D, or other procedure approved by the department. The department may require periodic confirmatory measurements (e.g., grab samples) during routine operations to verify the low emissions. Methods to implement periodic confirmatory monitoring shall be approved by the department.

(4) The department may allow a facility to use alternative monitoring procedures or methods if continuous monitoring is not a feasible or reasonable requirement.

(5) The following types of facilities shall determine radionuclide emissions in accordance with either a methodology referenced in subsections (1) through (4) of this section or the respective document referenced below:

(a) Nuclear power reactors licensed by the NRC: Offsite Dose Calculation Manual;

(b) Fuel fabrication plants licensed by the NRC: NRC's Regulatory Guide 4.16, dated December 1985;

(c) Uranium mills that are processing material: NRC's Regulatory Guide 4.14, dated April 1980.

(6) Licensed facilities shall conduct and document a quality assurance program. Except for those types of facilities specified in subsection (5) of this section, the quality assurance program shall be compatible with applicable national standards such as ANSI/ASME NQA-1-1988, ANSI/ASME NQA-2-1986, QAMS-004, and QAMS-005.

(7) Those types of facilities specified in subsection (5) of this section shall conduct and document a quality assurance program compatible with either the applicable national standards referenced in subsection (6) of this section or the NRC's Regulatory Guide 4.15, dated February 1979.

(8) Facilities shall monitor nonpoint and fugitive emissions of radioactive material.

(9) The department may conduct an environmental surveillance program to ensure that radiation doses to the public from emission units are in compliance with applicable standards. The department may require the operator of any emission unit to conduct stack sampling, ambient air monitoring, or other testing as necessary to demonstrate compliance with the standards in WAC 246-247-040.

(10) The department may require the owner or operator of an emission unit to make provision, at existing emission unit sampling stations, for the department to take split or collocated samples of the emissions.

(11) The planning for any proposed new construction or significant modification of the emission unit must address accidental releases with a probability of occurrence during the expected life of the emission unit of greater than one percent.

(12) All facilities must be able to demonstrate that appropriate supervisors and workers are adequately trained in the use and maintenance of emission control and monitoring systems, and in the performance of associated test and emergency response procedures.

(13) All facilities must be able to demonstrate the reliability and accuracy of the radioactive air emissions monitoring data.

[Statutory Authority: Chapters 70.98 and 70.94 RCW and chapter 173-480 WAC. 94-07-010, § 246-247-075, filed 3/4/94, effective 4/4/94.]

ENCLOSURE C

WAC 246-247-060 Applications, registration and licensing. This section describes the information requirements for approval to construct, modify, and operate an emission unit. Any notice of construction (NOC) requires the submittal of the information listed in Appendix A. Complex projects may require additional information. The applicant should contact the department early in the conceptual design phase for guidance on applicable control technologies to consider.

Appendices B and C outline the procedures to demonstrate compliance with the BARCT and ALARACT standards. Based on the Appendix A information provided, the department may advise the applicant which subset of technologies to consider as candidates for meeting BARCT or ALARACT requirements.

For those facilities subject to the operating permit regulations in chapter 173-401 WAC, the radioactive air emissions license will be incorporated as an applicable portion of the air operating permit issued by the department of ecology or a local air pollution control authority. The department will be responsible for determining the facility's compliance with and enforcing the requirements of the radioactive air emissions license.

(1) Requirements for new construction or modification of emission units.

(a) Early in the design phase, the applicant shall submit a NOC containing the information required in Appendix A.

(b) Within thirty days of receipt of the NOC, the department shall inform the applicant if additional information is required. The department may determine, on the basis of the information submitted, that the requirements of BARCT or ALARACT have been met, or may require the applicant to submit a BARCT or ALARACT demonstration compatible with Appendix B or C, respectively.

(c) Within sixty days of receipt of all required information, the department shall issue an approval or denial to construct. The department may require changes to the final proposed control technology.

(d) The applicant may request a phased approval process by so stating and submitting a limited application. The department may grant a conditional approval to construct for such activities as would not preclude the construction or installation of any control or monitoring equipment required after review of the completed application.

(e) The department shall issue a license, or amend an existing license, authorizing operation of the emission unit(s) when the proposed new construction or modification is complete. For facilities subject to the air operating permit requirements of chapter 173-401 WAC, the license shall become part of the air operating permit issued by the department of ecology or a local air pollution control authority. For new construction, this action shall constitute registration of the emission unit(s).

ENCLOSURE D

WAC 246-247-110 Appendix A—Application information requirements. (1) Name and address of the facility, and location (latitude and longitude) of the emission unit(s).

(2) Name, title, address, and phone number of the responsible manager.

(3) Identify the type of proposed action for which this application is submitted:

(a) Construction of new emission unit(s);

(b) Modification of existing emission unit(s); identify whether this is a significant modification;

(c) Modification of existing unit(s), unregistered.

(4) If this project is subject to the requirements of the State Environmental Policy Act (SEPA) contained in chapter 197-11 WAC, provide the name of the lead agency, lead agency contact person, and their phone number.

(5) Describe the chemical and physical processes upstream of the emission unit(s).

(6) Describe the existing and proposed (as applicable) abatement technology. Describe the basis for the use of the proposed system. Include expected efficiency of each control device, and the annual average volumetric flow rate(s) in meters^3/sec for the emission unit(s).

(7) Provide conceptual drawings showing all applicable control technology components from the point of entry of radionuclides into the vapor space to release to the environment.

(8) Identify each radionuclide that could contribute greater than ten percent of the potential-to-emit TEDE to the MEI, or greater than 0.1 mrem/yr potential-to-emit TEDE to the MEI.

(9) Describe the effluent monitoring system for the proposed control system. Describe each piece of monitoring equipment and its monitoring capability, including detection limits, for each radionuclide that could contribute greater than ten percent of the potential-to-emit TEDE to the MEI, or greater than 0.1 mrem/yr potential-to-emit TEDE to the MEI, or greater than twenty-five percent of the TEDE to the MEI, after controls. Describe the method for monitoring or calculating those radionuclide emissions. Describe the method with detail sufficient to demonstrate compliance with the applicable requirements.

(10) Indicate the annual possession quantity for each radionuclide.

(11) Indicate the physical form of each radionuclide in inventory: Solid, particulate solids, liquid, or gas.

(12) Indicate the release form of each radionuclide in inventory: Particulate solids, vapor, or gas. Give the chemical form and ICRP 30 solubility class, if known.

(13) Release rates.

(a) New emission unit(s): Give predicted release rates without any emissions control equipment (the potential-to-emit) and with the proposed control equipment using the efficiencies described in subsection (6) of this section.

(b) Modified emission unit(s): Give predicted release rates without any emissions control equipment (the potential-to-emit) and with the existing and proposed control equipment using the efficiencies described in subsection (6) of this section. Provide the latest year's emissions data or emissions estimates.

In all cases, indicate whether the emission unit is operating in a batch or continuous mode.

(14) Identify the MEI by distance and direction from the emission unit(s). The MEI is determined by considering distance, windrose data, presence of vegetable gardens, and meat or milk producing animals at unrestricted areas surrounding the emission unit.

(15) Calculate the TEDE to the MEI using an approved procedure (see WAC 246-247-085). For each radionuclide identified in subsection (8) of this section, determine the TEDE to the MEI for existing and proposed emission controls, and without any emission controls (the potential-to-emit) using the release rates from subsection (13) of this section. Provide all input data used in the calculations.

(16) Provide cost factors for construction, operation, and maintenance of the proposed control technology components and system, if a BARCT or ALARACT demonstration is not submitted with the NOC.

(17) Provide an estimate of the lifetime for the facility process with the emission rates provided in this application.

(18) Indicate which of the following control technology standards have been considered and will be complied with in the design and operation of the emission unit(s) described in this application:

ASME/ANSI AG-1, Code on Nuclear Air and Gas Treatment (where there are conflicts in standards with the other listed references, this standard shall take precedence)

ASME/ANSI N509, Nuclear Power Plant Air-Cleaning Units and Components

ASME/ANSI N510, Testing of Nuclear Air Treatment Systems

ANSI/ASME NQA-1, Quality Assurance Program Requirements for Nuclear Facilities

40 CFR 60, Appendix A, Methods 1, 1A, 2, 2A, 2C, 2D, 4, 5, and 17

ANSI N13.1, Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities

For each standard not so indicated, give reason(s) to support adequacy of the design and operation of the emission unit(s) as proposed.

[Statutory Authority: Chapters 70.98 and 70.94 RCW and chapter 173-480 WAC. 94-07-010, § 246-247-110, filed 3/4/94, effective 4/4/94.]

Department of Energy
Richland Operations Office
P.O. Box 550
Richland, Washington 99352

MAR 13 1996

96-PCA-149

Mr. Jerry Leitch, Chief
Radiation and Indoor Air Section
U.S. Environmental Protection Agency
Region 10
1200 Sixth Avenue
Seattle, Washington 98504-7827

Mr. Alan W. Conklin, Head
Air Emissions and Defense
Waste Section
Division of Radiation Protection
State of Washington
Department of Health
P.O. Box 47827
Olympia, Washington 98504-7827

RECEIVED
MAR 19 1996
DIVISION OF RADIATION PROTECTION

Dear Messrs. Conklin and Leitch:

NOTICE OF CONSTRUCTION (NOC) FOR OPERATION OF THE PLASMA ARC FURNACE IN THE 324 BUILDING WASTE TECHNOLOGY ENGINEERING LABORATORY

Attached is a NOC regarding the operation of a plasma arc furnace located in the 324 Building Waste Technology Engineering Laboratory on the Hanford site. The plasma arc furnace is a thermal treatment system that is being developed to treat buried waste from across the complex. This notification is provided pursuant to Washington Administrative Code 246-247 and 40 CFR 61.

If you have any questions, please contact Mr. Hector M. Rodriguez at (509) 376-6421.

Sincerely,

for James E. Rasmussen, Director
Environmental Assurance, Permits,
and Policy Division

EAP:HMR

Attachment

cc w/attach:
E. A. Flores, PNNL
G. A. Simiele, PNNL

Attachment 6

Department of Energy
Richland Operations Office
P.O. Box 550
Richland, Washington 99352

98-EAP-348

JUL 07 1998

Mr. A. W. Conklin, Head
State of Washington
Department of Health
Division of Radiation Protection
P.O. Box 47827
Olympia, Washington 98504-7827

Post-it® Fax Note 7671	Date 7-13-98	# of pages ▶ 3
To Emad Shahin	From John Schmidt	
Co./Dept. EPA	Co. WDOH	
Phone #	Phone # 377-3827	
Fax # 206 553 0119	Fax # 509 377 3871	

Dear Mr. Conklin:

REQUEST TO EXTEND TIME PERIOD FOR RESPONDING TO NOTICE OF VIOLATION (NOV) COMPLIANCE ORDER

This letter is in reference to the State of Washington Department of Health (DOH) letter from J. L. Erickson to J. E. Rasmussen, U.S. Department of Energy, Richland Operations Office (RL), "Notice of Violation," Air-98-01, dated May 13, 1998.

RL is requesting an extension to the 60-day response period specified in the referenced NOV; Compliance Order (CO) Item 3. This request is submitted pursuant to:

- Instructions contained in the referenced NOV – Section III of the referenced NOV states; "A request to extend a time period for good cause may be filed with DOH by sending a written request to Mr. Al Conklin at the above address within the time period specified for compliance. Any such request will be reviewed and a written response provided to you within ten (10) days of DOH's receipt of your request."

- Discussions between DOH and RL – On May 21, 1998, RL met with DOH to discuss the referenced NOV. During these discussions, DOH and RL agreed that an extension of the referenced 60-day response period would be necessary for some Hanford Site contractors/operations.

Subsequent to receiving the referenced NOV/CO, RL initiated response actions. The actions include:

- During the week of May 18, 1998, RL program/project offices provided verbal direction to associated Hanford Site contractors to initiate response actions.

- On May 21, 1998, RL met with DOH to discuss the referenced NOV.

- During the week of June 1, 1998, RL initiated an effort to account for all Hanford Site Notices of Construction (NOCs) requiring discrepancy reviews.

- In a letter dated June 4, 1998, RL requested Fluor Daniel Hanford, Inc. (FDH) to consolidate the responses from all Hanford Site contractors and to submit a report to RL, for subsequent transmittal to DOH. Pursuant to this request, FDH prepared documentation necessary to coordinate/guide the multi-contractor NOC discrepancy reviews. The documentation was distributed to Hanford Site contractors during the week of June 15, 1998. The documentation includes confirmation that the discrepancy reviews were performed and a table for documenting/compiling information about discrepancies.

- Discrepancy reviews for two Hanford Site prime contractors [Pacific Northwest National Laboratory (PNNL) and Bechtel Hanford, Inc. (BHI)] have been completed, and are provided as attachments to this letter. Please note, since the discrepancy reviews for PNNL and BHI have been completed, the proposed extension request, contained herein, would not necessarily apply to workscope under the management of PNNL and/or BHI.

RL has evaluated the required NOV/CO response actions and has concluded that it will not be feasible to complete all the actions within the referenced 60-day period. Some of the response actions are listed below.

- A large number of NOCs will need to be reviewed (approximately 100).
- Where NOC-related work activities have not been initiated, planned work will need to be reviewed (planned-work-reviews are expected to be more time intensive than actual-work-reviews).
- Some NOC discrepancy reviews will require the review of NOCs containing numerous and/or complex conditions of approval (e.g., extended schedules, special record keeping requirements, special emissions measurement requirements, special emissions control requirements, etc.).
- Some NOC discrepancy reviews will require the review of extensive and complex activities and/or equipment (e.g., multiple in-field procedures, multiple emission units, multiple and complex control technologies, etc.).
- Coordination will need to be provided for multiple Hanford Site contractors.
- Discrepancy review criteria had to be developed and distributed to Hanford Site contractors to accommodate the high degree of variability in Hanford Site NOCs.
- Discrepancy review documentation from multiple contractors will need to be compiled and reviewed for subsequent transmittal to DOH.

JUL 07 1998

It is RL's understanding that DOH expects the discrepancy reviews to be thorough (e.g., the reviews should allow for in-field verifications). However, based on the above information, RL believes it will not be feasible to perform thorough reviews of all Hanford Site NOCs within the referenced 60-day period, except as previously noted for workscope under PNNL and/or BHI management. If an extension is not provided, RL anticipates that some NOCs may not receive sufficiently thorough reviews. Therefore, RL concludes that "good cause" exists to support the requested extension. Pursuant to this conclusion, RL requests an immediate meeting with DOH to negotiate an extended schedule for responding to the referenced NOV/CO.

Should you have any questions regarding this information, please contact Hector M. Rodriguez, of my staff, on (509) 376-6421.

Sincerely,

for James E. Rasmussen, Director
Environmental Assurance, Permits,
and Policy Division

EAP:HMR

Attachments:
1. BHI NOC Discrepancies.
2. PNNL NOC Discrepancies

cc w/attachs:
R. J. Landon, BHI
J. R. Wilkinson, CTUIR
W. D. Adair, FDH
S. M. Price, FDH
Donna L. Powaukee, NPT
H. T. Tilden, PNNL
Russell Jim, YIN

TABLE 3-2
BOILER LOCATIONS IN THE 200 AREAS

Fuel	Area	Size (BHP)	Building Location	Number Needed
No. 2 Fuel Oil	200 West	80	Hills Construction Complex	1
		200	283-W / B-604	1
		200	222-S / 2716-S	2
		250	272-W / 2707-W / 277-W	1 272-BA
		350	234-5Z	3 234Z 001 002 003
No. 2 Fuel Oil	200 East	80	2707-E / 275-E / 2715-EC	1
		150	East/West Tank Farm*	1
		150	225-B	1
		200	283-E / B-604	1
		200	242-A	1
		700	242-A	2 242-A 002 003

* Portable boiler

250 HP

283-W

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 12:49:36

LIGHT OIL

O2 % 4.6
CO PPMN 5
Prs NOT FITTED
EFF % (G) 88.4
XAIR % 28
CO2 % 12.1

NO PPMN ... 71
NO2 PPMN 0
NOx PPMN ... 71
SO2 PPMN 2
REF. %O2 ... 3.0

NETT .. F 221.4
FLUE .. F 277.7
INLT NOT FITTED
AMBIENT F 56.3

272-OA

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 12:18:49

LIGHT OIL

O2 % 3.8
CO PPMN 6
Prs NOT FITTED
EFF % (G) 87.7
XAIR % 22
CO2 % 12.7

NO PPMN ... 80
NO2 PPMN 0
NOx PPMN ... 80
SO2 PPMN 7
REF. %O2 ... 3.0

NETT .. F 259.2
FLUE .. F 318.5
INLT NOT FITTED
AMBIENT F 59.3

225E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 11:34:59

LIGHT OIL

O2 % 3.9
CO PPMN 4
Prs NOT FITTED
EFF % (G) 87.1
XAIR % 23
CO2 % 12.5

NO PPMN ... 71
NO2 PPMN 0
NOx PPMN ... 71
SO2 PPMN 9
REF. %O2 ... 3.0

NETT .. F 278.4
FLUE .. F 344.3
INLT NOT FITTED
AMBIENT F 65.8

275E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 10:32:57

LIGHT OIL

O2 % 4.6
CO PPM 4
Prs NOT FITTED
EFF % (G) 87.9
XAIR % 28
CO2 % 12.0

NO PPM ... 196
NO2 PPM 0
NOx PPM ... 196
SO2 PPM 7

NETT .. F 239.2
FLUE .. F 299.3
INLT NOT FITTED
AMBIENT F 60.0

200CE

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 13:20:01

LIGHT OIL

O2 % 4.1
CO PPM 4
Prs NOT FITTED
EFF % (G) 87.8
XAIR % 24
CO2 % 12.5

NO PPM ... 210
NO2 PPM 0
NOx PPM ... 210
SO2 PPM 4

NETT .. F 247.5
FLUE .. F 307.2
INLT NOT FITTED
AMBIENT F 59.7

283E

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 09:50:01

LIGHT OIL

O2 % 3.6
CO PPMN ... 10
Prs NOT FITTED
EFF % (G) 88.1
XAIR % 20
CO2 % 12.8

NO PPMN ... 73
NO2 PPMN 0
NOx PPMN ... 73
SO2 PPMN ... 11
REF. %O2 ... 3.0

NETT .. F 243.3
FLUE .. F 297.1
INLT NOT FITTED
AMBIENT F 53.7

222S BLR 002

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 13:55:11

LIGHT OIL

O2 % 3.3
CO PPMN 8
Prs NOT FITTED
EFF % (G) 87.3
XAIR % 19
CO2 % 13.0

NO PPMN ... 67
NO2 PPMN 0
NOx PPMN ... 67
SO2 PPMN 4
REF. %O2 ... 3.0

NETT .. F 279.1
FLUE .. F 340.5
INLT NOT FITTED
AMBIENT F 61

2225 BLR 001

*** KANE-MAY ***
** KM QUINTOX **

DATE 11-13-97
TIME 14:06:13

LIGHT OIL

O2 % 4.3
CO PPMN 5
Prs NOT FITTED
EFF % (G) 87.5
XAIR % 25
CO2 % 12.3

NO PPMN ... 56
NO2 PPMN 0
NOx PPMN ... 56
SO2 PPMN 3
REF. %O2 ... 3.0

NETT .. F 262.9
FLUE .. F 324.8
INLT NOT FITTED
AMBIENT F 61.8

~~242A BLR 001~~

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 10:17:34

LIGHT OIL

O2 % 4.0
CO PPMN 6
Prs NOT FITTED
EFF % (G) 86.3
XAIR % 23
CO2 % 12.5

NO PPMN ... 69
NO2 PPMN 0
NOx PPMN ... 69
SO2 PPMN 7
REF. %O2 ... 3.0

NETT .. F 313.5
FLUE .. F 367.1
INLT NOT FITTED
AMBIENT F 53.6

242A BLR 002

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 10:04:57

LIGHT OIL

O2 % 3.5
CO PPMN ... 11
Prs NOT FITTED
EFF % (G) 88.7
XAIR % 20
CO2 % 12.9

NO PPMN ... 60
NO2 PPMN 0
NOx PPMN ... 60
SO2 PPMN 6
REF. %O2 ... 3.0

NETT .. F 217.6
FLUE .. F 266.3
INLT NOT FITTED
AMBIENT F 48.7

700 HP

242A BLR 003

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 09:59:48

LIGHT OIL

O2 % 3.4
CO PPMN 6
Prs NOT FITTED
EFF % (G) 88.9
XAIR % 19
CO2 % 13.0

NO PPMN 78
NO2 PPMN 0
NOx PPMN ... 78
SO2 PPMN 5
REF. %O2 ... 3.0

NETT .. F 208.8
FLUE .. F 255.9
INLT NOT FITTED
AMBIENT F 47.1

700 HP

350 HP

~~BLR 001 234Z~~

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:47:05

LIGHT OIL

O2 % 4.3
CO PPMN ... 37
Prs NOT FITTED
EFF % (G) 86.6
XAIR % 26
CO2 % 12.3

NO PPMN ... 84
NO2 PPMN 0
NOx PPMN ... 84
SO2 PPMN ... 15
REF. %O2 ... 3.0

NETT .. F 295.0
FLUE .. F 355.4
INLT NOT FITTED
AMBIENT F 60.4

350 HP

234Z BLR 002

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:38:16

LIGHT OIL

O2 % 4.3
CO PPMN ... 24
Prs NOT FITTED
EFF % (G) 86.4
XAIR % 25
CO2 % 12.3

NO PPMN ... 85
NO2 PPMN 0
NOx PPMN ... 85
SO2 PPMN ... 12
REF. %O2 ... 3.0

NETT .. F 302.2
FLUE .. F 361.5
INLT NOT FITTED
AMBIENT F 59.3

350 HP

~~234Z BLR 003~~

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 11:26:51

LIGHT OIL

O2 % 3.9
CO PPMN ... 21
Prs NOT FITTED
EFF % (G) 86.9
XAIR % 23
CO2 % 12.6

NO PPMN ... 85
NO2 PPMN 0
NOx PPMN ... 85
SO2 PPMN ... 13
REF. %O2 ... 3.0

NETT .. F 291.6
FLUE .. F 350.4
INLT NOT FITTED
AMBIENT F 58.6

MOBIL STEAM PLANT

*** KANE-MAY ***
** KM QUINTOX **

DATE 12-12-97
TIME 12:02:20

LIGHT OIL

O2 % 4.0
CO PPMN ... 22
Prs NOT FITTED
EFF % (G) 88.0
XAIR % 23
CO2 % 12.5

NO PPMN ... 95
NO2 PPMN 0
NOx PPMN ... 95
SO2 PPMN 1
REF. %O2 ... 3.0

NETT .. F 239.5
FLUE .. F 299.6
INLT NOT FITTED
AMBIENT F 60.0