OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
OREGON TITLE V OPERATING PERMIT and ACID RAIN PERMIT REVIEW REPORT

Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701

Unassigned emissions	
Emission credits	
Source test	X
COMS	X
CEMS	X
CAM	X
Ambient monitoring	
Compliance schedule	X

Special conditions	
Annual report	X
Semi-annual report	X
Quarterly report	X
Monthly report	
Excess emissions report	X
NSPS	D, Y
NESHAP	ZZZZ, DDDDD

NSR	
PSD	
RACT	
Acid Rain	X
Size	T-V
Major HAP source	X
Federal major source	X

TABLE OF CONTENTS

LIST OF ABBREVIATIONS USED IN THIS REVIEW REPORT 2
INTRODUCTION 3
PERMITTEE IDENTIFICATION 8
FACILITY DESCRIPTION 8
EMISSIONS UNIT AND POLLUTION CONTROL DEVICE IDENTIFICATION 9
EMISSION LIMITS AND STANDARDS, TESTING, AND MONITORING 14
RECORDKEEPING REQUIREMENTS 25
REPORTING REQUIREMENTS 25
PLANT SITE EMISSION LIMITS 25
HAZARDOUS AIR POLLUTANTS 27
GENERAL BACKGROUND INFORMATION 27
COMPLIANCE HISTORY 27
SOURCE TEST RESULTS 30
PUBLIC NOTICE 31
APPENDIX A: EMISSIONS DETAIL SHEET 32
APPENDIX B: EMISSION FACTOR DOCUMENTATION 33
APPENDIX C: PSEL DEFINITIONS 41
APPENDIX D: SUMMARY OF EXCES EMISSIONS 44
APPENDIX E: RESPONSE TO PUBLIC COMMENTS (4/27/06 – 7/7/06) 54
APPENDIX F: RESPONSE TO PUBLIC COMMENTS (4/11/07 – 6/15/07) 64
APPENDIX G: RESPONSE TO PUBLIC COMMENTS (4/1/10 – 8/16/10) 71

LIST OF ABBREVIATIONS USED IN THIS REVIEW REPORT

AMB	Ambient
AQMA	Air Quality Management Area
ASTM	American Society of Testing and Materials
BDT	Bone Dry Ton
CAM	Compliance Assurance Monitoring
CAMR	Clean Air Mercury Rule
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System
CO	Carbon Monoxide
COMPL	Compliance
COMS	Continuous Opacity Monitoring System
COND	Condition
CRED	Credit
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic feet
EF	Emission Factor
EPA	United States Environmental Protection Agency
EU	Emissions Unit
FCAA	Federal Clean Air Act
gr/dscf	grains per dry standard cubic feet
HAP	Hazardous Air Pollutant
ID	Identification Code
I&M	Inspection and Maintenance
MB	Material Balance
Mlb	1000 pounds
MON	Monitoring
NA	Not Applicable
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	Operation and Maintenance
Pb	Lead
PCD	Pollution Control Device
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns in size
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
SCHED	Schedule
SPEC	Special
SO_2	Sulfur Dioxide
ST	Source Test
VE	Visible Emissions
VMT	Vehicle Mile Traveled
VOC	Volatile Organic Compound

INTRODUCTION

1. This is a renewal of the Oregon Title V Operating Permit issued to Portland General Electric Company (PGE) on July 1, 2001 and scheduled to expire on July 1, 2006. A timely and complete application was submitted to the Department on June 22, 2005, so the current permit remains in effect until the permit renewal is issued. The Phase II Acid Rain Permit is also being renewed during this permit action.

   A draft of the permit was released for public comment on April 27, 2006. Public hearings were held on June 15, 2006 in Boardman, Oregon and on June 28, 2006 in Portland, Oregon. The comment period ended on July 7, 2006. A summary of the comments and the Department's response is provided in Appendix E. One of the people who commented pointed out a procedural error, so the comment period was reopened. At the same time, the Environmental Quality Commission (EQC) was about to take final action on a rule that would limit mercury emissions from coal fired power plants. Therefore, it was decided to hold off on the comment period until the mercury rule would be finalized and the requirements could be included in the permit renewal.

   A revised draft permit, updated review report, and response to comments were provided for public comment on April 11, 2007. Public hearings were held on May 16, 2007 in Boardman and May 31, 2007 in Portland. The comment period ended on June 15, 2007. A summary of the comments and the Department's responses are provided in Appendix F.

   Shortly after the end of the second comment period, the federal Clean Air Mercury Rules were vacated and the Department initiated a rulemaking to develop state rules that were independent of the federal rules. In addition, the Department anticipated that regional haze rules that would include Best Available Retrofit Technology would be adopted in 2008. Issuance of the permit has been postponed to include mercury and regional haze requirements that will require significant reductions in emissions. The mercury and regional haze rules were adopted on June 19, 2009. The draft permit has been revised to include the newly adopted requirements.

   The permit does not contain any requirements for carbon dioxide and greenhouse gases other than PGE must submit annual GHG emission reports in accordance with OAR 340, Division 215. EPA recently proposed rules that will add GHG as a regulated pollutant under the Clean Air Act. What, if any requirements will need to be added to the permit will depend on the timing of EPA's rules and how they will affect Oregon's program.

2. In accordance with OAR 340-028-2200(1)(f), this review report is intended to provide the legal and factual basis for the draft permit conditions. In most cases, the legal basis for a permit condition is included in the permit by citing the applicable regulation. The factual basis for the requirement may be the same as the legal basis. However, when the regulation is not specific and only provides general requirements, this review report is used to provide a more thorough explanation of the factual basis for the draft permit conditions.

3. During the previous permit term, PGE and/or the Department made the following changes to the permit, which will be incorporated into the permit renewal.

Date	Action	Brief Summary	Current Permit Action
10/15/01	Minor Permit Modification – Addendum 1	The short term Plant Site Emission Limits were removed from the permit in accordance with revisions to the regulations for Plant Site Emission Limits.	Incorporate change into the permit renewal
07/15/08	Administrative Amendment – Addendum 2	The excess emissions and permit deviation reporting requirements were revised in accordance with changes to the rules.	Incorporate changes into the permit renewal

4. In addition to the changes listed above, the permit is being revised to incorporate changes as a result of changes to regulations, as well as minor changes to the Title V model permits that the Department uses to draft Title V permits. Changes to the model permits are the result of program reviews both internally and by EPA to ensure that the permits include the necessary information from OAR 340-218-0050. Provided below is a summary of the changes being made to the permit:

New Permit Condition Number	Old Permit Condition Number	Description of Change	Reason for Change
Cover Page	Cover Page	Changed the address of the DEQ office in Bend; added the NAICS code; changed the designated representative for the Acid Rain program	Current information
1	1	No changes	NA
2	2	Revise condition 2.a to include mercury conditions that are not federally enforceable. Add condition 2.b to identify the Regional Haze requirements as state enforceable until they are approved by EPA as part of Oregon's SIP.	Revised regulations
3	3	Added requirement to submit a Notice of Intent to Construct prior to modifying or installing new pollution control equipment.	Approval is required by OAR 340-210-0215 and 340-218-0190. A Notice of Approval was issued for the low NO_x burners on 4/15/08. The conditions of that approval are provided in condition 30.
4 and 5	---	Added two conditions that deal with nuisances (odors and PM fallout).	These requirements were previously only applicable in certain areas of the state, but they are now applicable in all areas of the state.
6 – 11	4 – 9	No change	NA
12	---	Added a condition that addresses the federal accidental release regulations.	DEQ's model permit
Emissions Unit Specific Emission Limits and Standards Table	Emissions Unit Specific Emission Limits and Standards Table	Added the state opacity standard as an applicable requirement for the main boiler.	This change is for clarification because the main boiler had been subject to the requirement by virtue of permit condition 6.
13	10	No change	
14	11	Added the main boiler to this condition.	The state general opacity standard applies to all emissions units at the plant.
15-19	12 – 16	No change	NA

New Permit Condition Number	Old Permit Condition Number	Description of Change	Reason for Change
20	17	Added western bituminous coal to list of fuels allowed to be burned in the main boiler.	The plant has burning this in the past as referenced in section 6 of this review report.
21-24	18 – 21	No change	NA
25 - 30	----	Added regional haze requirements for NO_x, SO_2, and PM.	These rules were adopted by the EQC on June 19, 2009. They are only enforceable by the state until EPA approves the rules a part of the SIP.
31 - 38	---	Added the mercury rule requirements.	These rules were adopted in 2006, but most recently revised on June 19, 2009.
39	24	Renumbered and relocated this condition for the Acid Rain program.	
---	22	This condition that included short term Plant Site Emission Limits was deleted by the minor permit modification on 10/15/01	This change is based on a change in the regulations in which short term PSELs are no longer required in most areas of the state.
40	23	The PSEL for NO_x is reduced to 11,672 tons per year beginning 01/01/08. The NO_x PSEL is further reduced in 2011 and the PM & SO_2 PSELS are reduced beginning on 07/01/14 as a result of the regional haze requirements.	The PSEL for NO_x is reduced in accordance with OAR 340-222-0043(1).
41	25	Minor changes based on the model permit.	DEQ's model permit
42	26	The testing frequency for the main boiler is being changed from once a year to once a permit term provided the first annual test is less than ½ of the standard.	Data from 26 tests performed on the unit between 1983 – 2008 show there have been no exceedances of the 0.04 lb/mmBtu limit and the average of the test results is 0.012 lb/mmBtu (less than ½ of the standard)
43	27	No change	NA
---	28	This condition was deleted because it only defined "Modified EPA Method 9"	The definition has been moved to the definition/acronym page of the permit.
44 – 46	29 – 31	No change	NA
47	---	This condition for maintaining a complaint log and responding to complaints is included as a monitoring condition for the added nuisance conditions 4 and 5.	DEQ's model permit
48 – 50	32 – 34	No change	NA

New Permit Condition Number	Old Permit Condition Number	Description of Change	Reason for Change
51	35	Changed 51.c to clarify that the COMS must be operated at all times whether or not fuel is being combusted. Also changed 51.g to clarify that one minute averages may be used to demonstrate compliance with the state opacity standard in Condition 14.	The state opacity standard applies at all times and the COMS is used for monitoring compliance with the standard. Therefore, the COMS must be operating at all times and the data must be sufficient to determine the aggregate time in any hour that the opacity is equal to or greater than 20%.
52	---	Added mercury monitoring requirements.	These requirements are based on the rules adopted in 2006 and revised in June 2009.
53	36	Added a note to this condition clarifying that a separate analysis for the heating value of the coal is not necessary provided the fuel certification and or analyses required by condition 49 are sufficient for demonstrating compliance with Condition 7 (fuel sulfur limit).	This is a clarification to avoid unnecessary testing.
53 – 55	36 - 38	No changes	NA
56	39	This monitoring condition has been modified slightly to remove reference to short term PSEL monitoring. In addition, some of the emission unit/devices have been combined and new emission factors calculated.	The short term PSELs have been removed from the permit.
--	40	This condition that specified how to determine the total short term emissions has been deleted	The short term PSEL's have been removed from the permit.
56.d and e	41 - 42	No change, but renumbered as d and e of condition 56.	NA
57 - 60	43 - 46	No changes	NA
61	47	This recordkeeping condition has been modified slightly to remove reference to short term PSEL monitoring.	The short term PSELs have been removed from the permit.
62 – 67	48 – 53	Minor changes	Incorporate changes to 40 CFR, Part 75
68	---	Added Hg emissions monitoring recordkeeping requirements	These requirements are based on the rules adopted in 2006 and revised in June 2009.

New Permit Condition Number	Old Permit Condition Number	Description of Change	Reason for Change
69	58	In addition, to immediate notification, the permittee is now required to submit written reports within 15 days of all excess emissions events, including those that occur during startup and shutdown. "Immediate" notification is changed from 1 hour to 4 hours to accommodate source operations. If there is an excess emissions, the source operators are usually busy responding to the problem and can't always notify the Department within 1 hour.	The excess emissions rules were revised in 2007 to satisfy EPA requirements. Except for the change to the definition of "immediate", these changes were previously incorporated into the permit as Addendum D.
70	59	Notification of permit deviations is now required within 15 days instead of 7 days.	This change is based on a program review conducted by EPA and revisions to the excess emissions rules in 2007.
---	60	This condition was deleted	The requirement to submit source test reports is already contained in General Testing Condition 41.e.
71 -72	61 -62	These conditions are moved and renumbered	DEQ's model permit
73	54	This reporting condition has been modified to remove reporting of certain records that are no longer needed for the PSEL monitoring. Greenhouse gas emission reporting is added, as well as annual pollutant totals.	The green house gas reporting rules were adopted in 2008. The PSEL monitoring requirements were revised as a streamlining measure.
74	55	The semi-annual certification requirements are modify slightly to clarify when monitoring methods must be included in the certifications.	This change is based on a program review conducted by EPA.
75	56	No change	NA
76 and 77	---	Added regional haze reporting requirements	The regional haze Western Backstop (WEB) Sulfur Dioxide (SO2) Trading Program provisions were adopted in 2003.
78 - 86	63 - 71	No changes	NA
---	72	The agency addresses are no longer a permit condition	The addresses are not an applicable requirement, so it is not appropriate to have them as a permit condition.
87 – 88	---	Add mercury reporting requirements.	The mercury rules were adopted in 2006 and revised in June of 2009.
---	73	Eliminated condition.	The scope of the nonapplicable requirements was too broad. This is based on comments by EPA during their review of Oregon's Title V program.

New Permit Condition Number	Old Permit Condition Number	Description of Change	Reason for Change
G1 – G27	G1 – G28	Added condition G4 that addresses masking emissions.	This is based on a change to the regulations (OAR 340-208-0400)
Attachment 1	Attachment 1	The list of regulations that have different rule numbers in the State Implementation Plan (SIP) has been updated.	SIP approval.

PERMITTEE IDENTIFICATION

5. Portland General Electric (PGE) Company owns and operates an electric power generation facility located at Tower Road near Boardman, Oregon. The facility is a Phase II acid rain source.

FACILITY DESCRIPTION

6. A single Foster Wheeler pulverized coal fired boiler provides steam to a single Westinghouse turbine generator. A small Combustion Engineering oil fired package boiler provides startup steam. In addition to the boiler/turbine buildings, the site contains maintenance facilities, a coal storage/handling facility, and an ash handling/disposal facility. Low sulfur sub-bituminous or bituminous Western coal is delivered to the site by unit trains. The site is located in the semi-arid north-central region of the State, approximately 13 miles southwest of Boardman, Oregon. Elevation of the site is approximately 700 feet above sea level.

The basic operating scenario for the Boardman plant is burning fossil fuel (coal) in the main boiler making steam to generate electricity. For emissions purposes the main process can be broken down into three primary components; coal handling particulate matter, fuel burning combustion products, and ash handling particulate matter. In addition to these primary components, there are emissions from several support processes such as maintenance activities and vehicular traffic. The following is a more detailed description of the operating scenario components:

6.a. Coal is unloaded from trains at the dumper building to a conveyor system and is either fed directly to the plant or "stacked" out to the storage pile. Coal is "reclaimed" from the storage pile to feed the plant when trains are not available. Fugitive particulate emissions in the coal facility are from storage pile wind erosion, bulldozer operations on the pile, and drop transfer points along the coal yard conveyor system. A water based foam/binder dust suppressant is used to control emissions at the dumper and conveyor transfer points. Compacting is used to minimize storage pile wind erosion. Once in the plant, coal is transported by the in-plant conveyor system to silos where it is fed to pulverizers through gravimetric feeders. The pulverized coal is blown into the main boiler with combustion air. Vacuum collection systems with baghouses are used to control particulate matter at the conveyor transfer points within the boiler house. After the silos, the system is closed and there are no further coal dust emissions points.

6.b. Fuel Combustion takes place in the main boiler and the auxiliary boiler. The main boiler generates the steam necessary to drive the turbine generator which generates electric power. Pulverized coal is the fuel used for electric power production. However, oil burning ignitors are used during pulverizer startup to establish the conditions necessary to sustain coal combustion. Flue gas containing combustion products exits the boiler and leaves the site via the 650' tall main stack. Pollutants within the flue gas will include particulate, CO, NO_x, SO_2, VOC, and HAPS. Particulate emissions are controlled by a full flow cold side electrostatic precipitator (ESP). A proprietary flue gas conditioning agent can be injected at the ESP inlet to enhance ESP performance in the event of problems due to ash resistivity. Low NO_x burner technology and overfire air are used to minimize NO_x emissions. A continuous monitoring system in the main stack is used to measure opacity, SO_2, NO_x, CO_2, and stack flow. Steam is required by several plant systems during the plant startup sequence before it is available from the main boiler. This steam is provided by the oil fired auxiliary boiler. The auxiliary boiler is only used for plant startup and once the steam pressure is available from the main boiler the auxiliary boiler is shut down. The auxiliary boiler has its own stack with no monitoring equipment and good combustion practices are used to minimize emissions.

6.c. Three types of ash result from the combustion process; bottom ash, economizer ash, and fly ash. The bottom ash is the heaviest material. It falls out in the main boiler where it is collected and transported by a water based system which precludes particulate emissions. Economizer ash is lighter material that falls out in the economizer section of the boiler. This ash is collected and transported in a closed pneumatic system. The only potential emission point in the economizer ash system is truck loading and this point is controlled by a vacuum system which returns dust to the fly ash handling system. Fly ash is the fine light ash collected by the electrostatic precipitator. The fly ash is transported by a closed pneumatic system to storage silos and to transportation vehicles. Emissions from fly ash transfers are controlled by negative pressure systems with baghouses. Ash is transported to the site ash disposal area or off site for sale as a concrete additive. Vehicles transporting dry ash are closed and water is applied daily to the ash disposal area whenever dry ash is being deposited.

EMISSIONS UNIT AND POLLUTION CONTROL DEVICE IDENTIFICATION

7. Summary of ID Numbers for Boardman Plant Title V Application

ID#	**Description**
OS1	Plant operating scenario.

Device\Process IDs:

AB.DV	Auxiliary boiler
MB.DV	Main boiler

Control Device IDs:

FADB.CD	Fly ash dome baghouse
FASNB.CD	Fly ash silo north baghouse
FASSB.CD	Fly ash silo south baghouse.
FAUB.CD	Fly ash unloading silo baghouse.
IPCNB.CD	North in plant coal handling baghouse.
IPCSB.CD	South in plant coal handling baghouse.
MBESP.CD	Main boiler electrostatic precipitator.

Emission Unit IDs:

AB.EU	Auxiliary boiler, emissions unit
AI4.EU	Aggregate Insignificant Emission Unit (4 sources)
MB.EU	Main boiler, emissions unit
CSP.EU	Coal storage pile
CYB.EU	Coal yard bulldozer activity
URT.EU	Unpaved road vehicle traffic.

Aggregate Insignificant Emission Unit IDs:

CYC.AIEU	Coal yard conveyor system
FA.AIEU	Fly ash handling
IPC.AIEU	In plant coal handling conveyor system.
PRT.AIEU	Paved road vehicle traffic.

Compliance Demonstration Point IDs:

ABS.CDP	Auxiliary boiler stack
FADV.CDP	Fly ash dome baghouse vent.
FASNV.CDP	Fly ash silo north baghouse vent.
FASSV.CDP	Fly ash silo south baghouse vent.
FAUV.CDP	Fly ash unloading silo baghouse vent.
IPCNV.CDP	North in plant coal handling baghouse vent.
IPCSV.CDP	South in plant coal handling baghouse vent.
MBS.CDP	Main boiler stack.

8. Provided below is a description of each of the emissions units at this facility:

8.a. Main boiler (MB.EU): The main boiler generates steam used for electric power generation. The boiler is a Foster Wheeler wall fired dry bottom boiler with low NO_x burners and overfire air ports. It consists of a water wall furnace with additional sections for superheat, reheat, and economizer heat recovery. The primary fuel is pulverized sub-bituminous coal. There are eight pulverizers, each feeding 4 burners for a total of 32 burners. Oil burning igniters are used during pulverizer startup. The boiler is rated at 5,793 million Btu/hr heat input or 350 tons of coal per hour. The nominal gross electric generating capacity is approximately 615 mega-watts, which is greater than the original design of 550 MW due to process improvements that have increased the efficiency.

An electrostatic precipitator (MBESP.CD) is used for particulate matter emissions control. The model B12LCS6F-15x40-126-2 ESP was manufactured by Lodge-Cotrell Dresser. The dry ESP is designed for an inlet gas flow rate of approximately 2,604,000 acfm. There are 6 fields. The design primary and secondary voltage is 450VAC and 55kVDC; respectively. The design primary and secondary current is 110AAC and 650mADC; respectively.

8.b. Auxiliary boiler (AB.EU): The auxiliary boiler is a Combustion Engineering package type, single burner, shop assembled boiler rated at 187 million Btu/hr heat input. This boiler is used for plant startup. ASTM Grade 2 distillate oil is the only fuel burned in the boiler. There are no add-on control devices.

8.c. Coal storage pile (CSP.EU): Coal is stored in a pile that is approximately 25' high by 500' wide by 1900' long. The surface area of the pile is, on the average, approximately 1,000,000 ft^2. Wind erosion causes some fugitive dust emissions.

8.d. Coal yard bulldozer activity (CYB.EU): Three different bulldozers are used to move coal around on the coal pile. This activity causes some fugitive dust emissions.

8.e. Unpaved road vehicle traffic (URT.EU): Major traffic bearing roads are paved (approximately 4 miles total). However, there are a number of sections of gravel roads which are regularly used. Vehicle traffic on these unpaved surfaces causes some fugitive dust emissions.

8.f. Coal processing equipment (CP.EU): A unique emission unit for coal processing equipment [coal yard conveyor system (CYC.AIEU) and in plant coal handling conveyor system (CYC.AIEU)] is identified in the permit because there is an applicable NSPS opacity limit for these activities. However, the particulate matter emissions from these activities are insignificant (<1 ton/yr) so the coal processing equipment is also included in the Aggregate insignificant activities (AI) for purposes of the PSEL. The equipment and activities included in the CP.EU emissions unit are defined below.

8.g. Aggregate insignificant activities (AI): The aggregate insignificant emissions activities at the facility include coal yard conveyor system (CYC.AIEU), fly ash handling (FA.AIEU), in plant coal handling conveyor system (IPC.AIEU), and paved road vehicle traffic (PRT.AIEU). All of the activities included in the aggregate insignificant emissions unit generate less than 1 ton/yr of combined particulate matter emissions. A description of each of the activities is provided below:

8.g.i. Coal is transferred to the plant under three scenarios:

8.g.i.A. Coal is moved directly from the train cars to the crusher via a conveyor system that includes nine drop points. This constitutes approximately 65% of the total coal transfer operations.

8.g.i.B. Coal is moved from the coal storage pile via a conveyor system that includes twelve drop points. This constitutes approximately 35% of the total coal transfer operations.

8.g.i.C. Coal is moved from a reclaim pit near the rail car dumper via a conveyor system that includes twelve drop points. This constitutes approximately 5% of the total coal transfer operations.

8.g.ii. The coal yard conveyor system (CYC.AIEU) consists of the following:

8.g.ii.A. Rotary dumper building where a water spray curtain is applied over the rail cars as they are being tipped. Visible emissions will prompt operators to increase application of Betz foam and binder system to minimize fugitive emissions.

8.g.ii.B. Transfer point 1 (TP-1), between conveyors U-1 and U-2, where a water spray is activated by coal on the conveyor.

8.g.ii.C. Reclaim point 1 (RP-1), where a water spray is activated by coal on the conveyor.

8.g.ii.D. Transfer point 2 (TP-2), between conveyors U-2 and U-3, where a water spray is activated by coal on the conveyor.

8.g.ii.E. Transfer point 3 (TP-3), between conveyor U-3 and SR-2, where a water spray is activated by coal on the conveyor.

8.g.ii.F. Stacker/reclaimer 2 (SR-2), which can stack up to 3500 tons/hr and reclaim from 400 to 2000 tons/hr, where a Betz foam system is activated by coal on the conveyor. An increase in fugitive emissions will prompt the operators to increase foam application.

8.g.ii.G. Transfer point 4 (TP-4), between SR-2 and SR-3, where a sonic fog system (fine water spray) is activated by coal on the conveyor.

8.g.ii.H. Stacker/reclaimer 3 (SR-3), which can stack up to 3500 tons/hr and reclaim from 130 to 1300 tons/hr, where emissions are controlled by residual effects of measures taken upstream.

8.g.ii.I. Transfer point-5 (TP-5), between SR-3 and conveyor R-2, where a Betz foam system is activated by coal on the conveyor.

8.g.ii.J. Reclaim point 2 (RP-2), where a Betz foam system is activated by coal on the conveyor.

8.g.ii.K. Belt conveyor (R-2) is a completely enclosed conveyor.

8.g.ii.L. Belt conveyor (R-8) is a completely enclosed conveyor. Visible emissions from the enclosure vents will prompt the operators to increase foam application upstream (TP-5 & RP-2).

8.g.ii.M. Crusher building has a water spray available if measures taken upstream do not reduce emissions.

8.g.ii.N. Belt conveyor (R-5) carries crushed coal to the plant and is a completely enclosed conveyor. Visible emissions from the enclosure vents will prompt operator to increase foam application upstream (TP-5 & RP-2).

8.g.ii.O. Belt conveyor (R-6) carries crushed coal to the plant and is a completely enclosed conveyor. Visible emissions from the enclosure vents will prompt operator to increase foam application upstream (TP-5 & RP-2).

8.g.iii. The in-plant coal conveyor system (IPC.AIEU) consists of two Peabody baghouses that serve the North and South coal dust collectors. A high pressure drop alarm is installed in the main control room. The dust collected in the baghouses is returned to the plant fuel system at the pulverizer silo.

8.g.iv. The fly ash handling system (FA.AIEU) consists of:

8.g.iv.A. North silo vent, which is controlled by a Mikro-Pulsaire baghouse. A high pressure drop alarm is installed in the main control room. The dust collected in the baghouse is returned to the plant fly ash silo.

8.g.iv.B. South silo vent, which is controlled by a Mikro-Pulsaire baghouse. A high pressure drop alarm is installed in the main control room. The dust collected in the baghouse is returned to the plant fly ash silo.

8.g.iv.C. Weigh bin vent, visible emissions will prompt operators to clean vent return line.

8.g.iv.D. East unloading spout, visible emissions will prompt operators to request corrective maintenance.

8.g.iv.E. West unloading spout, visible emissions will prompt operators to request corrective maintenance.

8.g.iv.F. Fly ash haul truck unloading is performed at low vehicle speeds during calm/low wind speeds. If visible emissions occur during unloading, a water blanket is applied. Unloading is not performed during high wind speeds.

8.g.iv.G. Economizer ash handling bin vent, visible emissions will prompt operators to clean vent return line.

8.g.iv.H. Economizer ash unloading spout, visible emissions will prompt operators to request corrective maintenance.

8.g.iv.I. Economizer ash haul truck unloading is performed at low vehicle speeds during calm/low wind speeds. If visible emissions occur during unloading, a water blanket is applied. Unloading is not performed during high wind speeds.

8.g.iv.J. Ash handling emissions which were previously permitted under ACDP 25-0030 include the following:

- An ash storage dome silo which is vented to a Mikro-Pulsaire baghouse. The baghouse was installed in 1993 and has a rated efficiency of 99.9%.
- A truck load-out silo which is vented to a Mikro-Pulsaire baghouse. The baghouse was installed in 1993 and has a rated efficiency of 99.9%.

8.h. As noted above, some of the fugitive dust emissions are controlled by baghouses. All of the baghouses use pulse jets of compressed air to clean the bags once every 30 seconds. Other information about the specific baghouses is provided in the following table:

Activity Controlled	Baghouse Identification	Manufacturer	Model Number	Design Inlet Gas Flow Rate (acfm)	Design Air-to-Cloth Ratio	Number of Bags	Design Pressure Drop ("H_2O)
Fly ash dome	FADB.CD	Mikro-Pulsaire	100 S 10 20B	6600	5.7:1	100	12
Fly ash silo north	FASNB.CD	Mikro-Pulsaire	96 K 8 TRH "B"	4680	5.2:1	96	12
Fly ash silo south	FASSB.CD	Mikro-Pulsaire	96 K 8 TRH "B"	4680	5.2:1	96	12
Fly ash unloading silo	FAUB.CD	Mikro-Pulsaire	36 S 10 30B	2100	5.6:1	36	12
North in plant coal handling	IPCNB.CD	Peabody Air Resources	PMTR-10-308-T	20000	5.5:1	308	14
South in plant coal handling	IPCSB.CD	Peabody Air Resources	PMTR-10-220-T	14000	5.4:1	220	14

9. Categorically insignificant activities include the following:

- Constituents of a chemical mixture present at less than 1% by weight of any chemical or compound regulated under Divisions 20 through 32 of this chapter, or less than 0.1% by weight of any carcinogen listed in the U.S. Department of Health and Human Service's Annual Report on Carcinogens when usage of the chemical mixture is less than 100,000 pounds/year
- Evaporative and tail pipe emissions from on-site motor vehicle operation
- Natural gas and propane burning equipment rated at less than or equal to 2.0 million Btu/hr
- Office activities
- Janitorial activities
- Groundskeeping activities including, but not limited to building painting and road and parking lot maintenance
- Instrument calibration
- Maintenance and repair shop
- Automotive repair shops or storage garages
- Air cooling or ventilating equipment not designed to remove air contaminants generated by or released from associated equipment
- Refrigeration systems with less than 50 pounds of charge of ozone depleting substances regulated under Title VI, including pressure tanks used in refrigeration systems but excluding any combustion equipment associated with such systems
- Bench scale laboratory equipment and laboratory equipment used exclusively for chemical and physical analysis, including associated vacuum producing devices but excluding research and development facilities
- Temporary construction activities
- Warehouse activities
- Accidental fires
- Air vents from air compressors
- Air purification systems
- Continuous emissions monitoring vent lines
- Demineralized water tanks
- Pre-treatment of municipal water, including use of deionized water purification systems
- Electrical charging stations
- Fire brigade training
- Instrument air dryers and distribution
- Process raw water filtration systems

- Routine maintenance, repair, and replacement such as anticipated activities most often associated with and performed during regularly scheduled equipment outages to maintain a plant and its equipment in good operating condition, including but not limited to steam cleaning, abrasive use, and woodworking
- Electric motors
- Storage tanks, reservoirs, transfer and lubricating equipment used for ASTM grade distillate or residual fuels, lubricants, and hydraulic fluids
- On-site storage tanks not subject to any New Source Performance Standards (NSPS), including underground storage tanks (UST), storing gasoline or diesel used exclusively for fueling of the facility's fleet of vehicles
- Natural gas, propane, and liquefied petroleum gas (LPG) storage tanks and transfer equipment
- Pressurized tanks containing gaseous compounds
- Storm water settling basins
- Fire suppression and training
- Health, safety, and emergency response activities
- Emergency generators and pumps used only during loss of primary equipment or utility service
- Non-contact steam vents and leaks and safety and relief valves for boiler steam distribution systems
- Non-contact steam condensate flash tanks
- Non-contact steam vents on condensate receivers, deaerators and similar equipment
- Boiler blowdown tanks
- Ash piles maintained in a wetted condition and associated handling systems and activities
- Oil/water separators in effluent treatment systems
- Combustion source flame safety purging on startup

EMISSION LIMITS AND STANDARDS, TESTING, AND MONITORING

10. Provided below is a discussion of the testing and monitoring requirements for the emission limits and standards that apply to each emissions unit.

Facility wide emission limits and standards:

11. Division 208 nuisance rules:

    11.a. Standards: OAR 340-208-0300 (nuisance prohibited) and 340-208-0450 (PM fallout prohibited) have been added to the permit because they are now applicable to all areas of the state.
    11.b. Testing requirements: Testing is not required because these requirements do not have any emissions limits that test results could be compared to for demonstrating compliance.
    11.c. Monitoring requirements: One way of determining whether a source is causing a nuisance is whether or not there are complaints about the source and whether the complaints are valid. Therefore, the permittee is required to maintain a complaint log and investigate any complaints. The complaint log will be reviewed by the Department personnel who will determine whether or not there is a nuisance condition.

12. Visible emissions:

    12.a. Emissions Limit: The 20% opacity limit in OAR 340-208-0110(2) applies to all emissions units and activities at the plant because the plant was built after 1970.
    12.b. Testing requirements: The rules do not require any specific testing and, except for the main boiler and auxiliary boiler that are discussed later, testing is not required in this permit because most of the emission sources are fugitives, which are difficult to measure in accordance with the reference test method (modified EPA method 9). Instead, a combination of fugitive emissions control work practices identified below and daily visible emissions surveys are used to assure compliance with the limit.

12.c. Monitoring requirements: The rules do not require any specific monitoring. To satisfy the Title V periodic monitoring requirements, the permittee is required to perform a facility wide visible emissions survey each day to determine if any visible emissions are leaving the plant site boundaries. The emissions limit cannot be exceeded if there are no visible emissions leaving the plant site boundaries. If there are visible emissions leaving the plant site boundaries, the permittee may either perform a modified EPA Method 9 test within 24 hours to demonstrate that the visible emissions are less than the emissions limit or immediately take corrective action to minimize the fugitive emissions. The permittee must maintain records of the surveys and corrective actions, if necessary.

13. Fuel sulfur limits:

13.a. Applicable requirements: Both ASTM grade #2 fuel oil (distillate oil) and coal are burned at the plant. OAR 340-228-0110(2) limits the sulfur content of #2 fuel oil to 0.5% by weight. OAR 340-228-0120 limits the sulfur content of coal to 1% by weight.

13.b. Testing requirements: The rules do not require any specific testing, but the permit specifies that the permittee may use either vendor certificates to show compliance with the fuel sulfur limits or analyze representative samples of the fuels in accordance with ASTM procedures.

13.c. Monitoring requirements: The rules do not require any specific monitoring. To satisfy the Title V periodic monitoring requirements, the permittee is required to maintain records of the sulfur content of each shipment of fuel received.

14. Fugitive dust:

14.a. Applicable requirements: The permit includes work practice requirements for preventing fugitive emissions from vehicle traffic on unpaved surfaces, material storage containers, the handling of fly and bottom ash, and the handling of coal. These requirements were identified in the Air Contaminant Discharge Permit (ACDP) issued on 7/19/95. However, there is no underlying regulatory authority for the requirements other than the ACDP so these requirements are only enforceable by the state.

14.b. Testing requirements: Testing is not required because these requirements do not have any emissions limits that test results could be compared to for demonstrating compliance.

14.c. Monitoring requirements: The ACDP did not require any specific monitoring requirements. To satisfy the Title V periodic monitoring requirements, the permittee is required to maintain records of the daily visual emissions surveys discussed above and maintain records of maintenance or corrective actions taken to prevent fugitive dust emissions.

Main Boiler:

15. New Source Performance Standards (NSPS): The main boiler is subject to 40 CFR Part 60 subpart D because it is a fossil-fuel-fired steam generator with a heat input capacity greater than 250 million Btu per hour and construction commenced after August 17, 1971. The boiler could also be subject to subparts Da or Db if construction commenced after the applicability dates for those subparts, or if the boiler was "modified," as that term is defined by NSPS rules, after the applicability dates for those subparts. The boiler's construction commenced in 1975 prior to the applicability dates for those subparts, and therefore is not subject to subparts Da or Db on that basis.

The following table identifies the applicable requirements from the NSPS general provisions (subpart A) and the specific requirements of subpart D are discussed after the general provisions.

Section	Requirement	Permit Action
60.7(a)	Notifications	This section is not applicable because the affected facility already exists at the plant and these requirements should have been satisfied.
60.7(b)	Records of startup/ shutdown/malfunctions	This is an applicable requirement that is included in the Recordkeeping Requirements section of the permit.
60.7(c), 60.7(d), and 60.7(e)	Excess emissions reporting	These are applicable requirements that are included in the Reporting Requirements section of the permit.
60.7(f)	Maintenance records	This is an applicable requirement that is included in the Recordkeeping Requirements section of the permit.
60.8	Performance tests	The initial performance test has been completed but the permittee is required to perform ongoing testing at least once a year. Therefore, these requirements are applicable and they are incorporated by reference.
60.11(b) and 60.11(e)	Opacity observation in conjunction with performance test	The permittee uses the COMS to demonstrate compliance, so 60.11(b) is not applicable. The COMS requirements are included in the permit.
60.11(d)	Good air pollution control practices	This is an applicable requirement that is included in the permit.
60.11(g)	Credible evidence	This is an applicable requirement that is incorporated into the permit by reference as part of general Condition G4.
60.12	Circumvention	This is an applicable requirement that is included in the permit.
60.13	Monitoring requirements	This is an applicable requirement that is included in the permit.
60.14	Modification	DEQ has not made a determination of non-applicability of these provisions.
60.15	Reconstruction	These provisions are not currently applicable to the source but could be applicable in the future.
60.18	General control device requirements	These provisions are not applicable because flares are not used at the source.

16. Visible emissions:

16.a. Applicable requirements: In addition to the general visible emissions standard identified above, the main boiler is subject to a 20% opacity limit (six minute average), except that one six minute period during an hour may be as high as 27% opacity, in accordance with 40 CFR §60.42(a)(2). These limits are New Source Performance Standards that do not apply during periods of startup, shutdown, or malfunction according to 40 CFR 60.8(c).

16.b. Testing requirements: Visible emissions testing is not required because emissions are monitored with a continuous opacity monitoring system (COMS) that is used for determining compliance with the standards.

16.c. Monitoring requirements: Visible emissions are monitored with a COMS in accordance with 40 CFR §60.45(a) and 40 CFR §75.14(a). The data is reduced to six minute averages for determining compliance with the NSPS limits. The data will also be reduced to one-minute averages to determine compliance with state opacity limit. The NSPS limit applies while fuel is combusted in the boiler. The state limit applies at all times.

17. Particulate matter:

17.a. Applicable requirement: Besides the plant site emission limit (PSEL), which is discussed later, there are three particulate matter emission limits that apply to the main boiler. The first is the state's generic grain loading limit of 0.1 gr/dscf specified in OAR 340-226-0210(1)(b) for new units installed after June of 1970. This limit is based on total particulate matter as measured by ODEQ Method 5 and corrected to 12% CO_2 or 50% excess air. The other two limits are in terms of pounds of emission per million Btu heat input (lb/million Btu) and are based only on the "front half" particulate matter as measured by EPA Method 5. In addition, the lb/million Btu limits do not apply during periods of startup, shutdown, or malfunction in accordance with 40 CFR §60.8(c);

whereas, the grain loading limit applies at all times. Of the two lb/million Btu limits, only the most stringent limit is included in the permit in accordance with EPA's streamlining guidance from White Paper 2. The lower limit (0.04 lb/million Btu) was established during the initial permitting of the facility to meet the Department's highest and best practicable treatment and control requirements in place at the time (currently OAR 340, division 226). The second limit is the NSPS limit of 0.10 lb/million Btu from 40 CFR §60.42(a)(1). Since both limits are based on EPA Method 5 and have the same applicability (e.g., do not apply during startup, shutdown, or malfunction), only the more stringent of the two is included in the permit, but both underlying rules are cited as the authority for the limit.

17.b. Testing requirements: The permit requires annual emissions tests unless the test results are less than half of the standard, then no further testing is required until the compliance date of the regional haze rules. PGE performed quarterly testing in the early '90's and annual testing since that time. The results have been well below the standard, averaging around 0.012 lb/mmBtu (30% of the standard). Based on the compliance record, the testing frequency is being reduced from annual to once during the permit term if the next annual test is less than 0.020 lb/mmBtu. A combined ODEQ Method 5 and EPA Method 5 test is required to be performed in accordance with the Department's Source Sampling Manual and 40 CFR §60.8 with the results of the DEQ method used to determine compliance with the state grain loading limit (0.1 gr/dscf) and the results of the EPA method used for determining compliance with the 0.04 lb/million Btu limit.

17.c. Monitoring requirements: The NSPS requires a COMS and reporting of excess emissions relative to the visible emissions limits. For a source of this magnitude (1015 tons of PM emissions per year with controls and potentially 52,800 tons per year without controls), it would be desirable to continuously monitor actual particulate emissions. However, at the time that CAM was established for this facility a CEMS performance specification had not been developed for PM continuous emission monitoring systems, so it was not possible to ensure reliable results. Therefore, the COMS is used to determine if the pollution control device (ESP) is operating properly. It has been demonstrated through several years of testing that the particulate emissions are well below the emission limits when the ESP is operating properly as indicated by an opacity less than 12%. A summary of emissions test results is provided in the Source Testing section of this review report. Using this data, a linear correlation was developed that shows that the particulate emissions are approximately 50% of the standard at an opacity of 12%. Therefore, the permit includes an action level of 12% opacity based on a one hour average. A one-hour average is used for the action level because the PM performance tests are at least one hour long. If there is an excursion of the action level, the permittee must perform corrective action to ensure that the ESP is operating properly. The permittee is required to maintain records of any action level excursions and subsequent corrective action. In addition, the permittee is required to develop and implement a quality improvement plan (QIP) if the duration of excursions during any semi-annual reporting period exceeds 5% of the total operating time. This monitoring satisfies both the Title V monitoring requirements (40 CFR, Part 70) and the Compliance Assurance Monitoring (CAM) requirements of 40 CFR, Part 64 as discussed later.

18. Sulfur dioxide:

18.a. Applicable requirements: The main boiler is subject to the following sulfur dioxide limits:

Fuel	Regulation	Emissions Limit (lb/million Btu heat input)	Averaging Period
Oil	OAR 340-228-0200(2)(a) and 40 CFR §60.43(a)(1)	0.8	3 hours (block)
Coal	OAR 340-228-0200(2)(b) and 40 CFR §60.43(a)(2)	1.2	3 hours (block)
Combined Fuels*	40 CFR §60.43(b)	1.2	3 hours (block)
Any Fuel (regional haze)	OAR 340-223-0030(1)(b), effective 7/1/14	0.12	30-day rolling average

*During the initial startup of the unit, fuel oil is burned exclusively. After the initial startup period, coal is the primary fuel but some fuel oil is routinely burned to ignite individual coal pulverizers. PGE has eight pulverizers and normally runs on six. Occasionally (once every one to two weeks) a new pulveriser is put into service so that one can be taken off for maintenance. Oil use is required when the pulverizers are changed. However, the amount of fuel oil burned simultaneously with coal for the purpose of igniting the coal pulverizers is trivial compared to the amount of coal burned and would not alter the limit for burning just coal, taking into consideration the significant figures of the standard. For example, the amount of oil typically burned in any one hour period is 480 gallons and the amount of coal is 350 tons. When the fuel rates are converted to heat inputs and put into the formula provided in 40 CFR 60.43(b), the resulting emission limit would be 1.1956 lb SO_2/mmBtu. When rounded to the significant figures of the standards, there is no change from the coal limit. Therefore, 40 CFR 60.43(b) is not included in the permit as an applicable requirement.

480 gallons of oil x 134,000 Btu/gal = 64.1 million Btu
350 tons of coal x 2000 lbs/ton x 8276 Btu/lb = 5793 million Btu
Total heat input = 64.1 + 5793 = 5857
% heat input from oil = 64/5857 x 100 = 1.09
% heat input from coal = 5793/5857 x 100 = 98.91

PS_{so2} = [1.09(0.80) + 98.91(1.20)]/(1.09 + 98.91) = 1.1956 = 1.2

18.b. Testing requirements: Relative accuracy test audits (RATA) are required annually as part of the CEMS quality assurance program.

18.c. Monitoring requirements: Sulfur dioxide emissions are monitored with a CEMS in accordance with the Acid Rain regulations (40 CFR, part 75), NSPS regulations (40 CFR §§60.45 and 60.13), and the Department's Continuous Monitoring Manual. The CEMS records 3-hour averages for determining compliance with the NSPS limit while burning coal. The CEMS is also used to verify that hourly emissions are less than 1.2 lb/million Btu (0.12 in 2014). While burning oil, the CEMS will continue to monitor sulfur dioxide emissions for purposes of the acid rain program, but the NSPS and state limits cannot be exceeded if the fuel oil meets the specifications of ASTM Grade #2 and the sulfur content of the fuel is less than or equal to 0.5% by weight as required by OAR 340-228-0110(2). The maximum sulfur dioxide emissions while burning oil is determined as follows:

E_{SO2} = %S/100 x 1000000/HV x 64/32
= 0.58 lb/million Btu heat input

Where:

E_{SO2} = Sulfur dioxide emissions in lb/million Btu heat input
%S = Maximum allowable sulfur content of the fuel oil
= 0.5%
HV = Approximate heating value of #2 distillate oil (Btu/lb)
= 17,290 Btu/lb (134,000 Btu/gallon x 7.75 lb/gallon)

Complying with the fuel oil sulfur limits provides a 25% margin of safety for complying with the stack emission limits (0.58 versus 0.8 lb/million Btu). As discussed above, PGE is required to monitor the fuel sulfur content of each type of fuel used in the boiler.

The CEMS measures the pollutant concentration and stack gas flow rate to calculate mass emission rates (lb/hr). The CEMS also calculates emission rates in units of the standard (lb/million Btu heat input) using fuel factors, diluent gas concentrations (%CO_2), and the appropriate equation in 40 CFR Part 60, appendix A, Method 19. The equations in Method 19 use different fuel factors for the different types of fuels, but instead of switching factors, PGE uses the coal factor for emission calculations while burning coal or oil. This will result in over estimating SO_2 emissions when burning oil because the F factor for coal is greater than the F factor for oil. Using this approach, the actual emissions will be less than the over estimated emissions that is used for determining compliance with the standards.

19. Nitrogen oxides:

19.a. Applicable requirements: The main boiler is subject to the following NSPS and Acid Rain nitrogen oxide limits:

Fuel	Regulation	Emissions Limit (lb/million Btu heat input)	Averaging Period
Oil	40 CFR §60.44(a)(2)	0.30	3 hours (block)
Coal	40 CFR §60.44(a)(3)	0.70	3 hours (block)
Combined Fuels*	40 CFR §60.44(b)	0.70	3 hours (block)
Coal	40 CFR §76.5(a)(2) and §76.8	0.46	annual average
Any Fuel (regional haze)	OAR 340-223-0030(1)(a), effective 7/1/11	0.28	30-day rolling average
	OAR 340-223-0030(1)(a), effective 7/1/11	0.23	12-month rolling average
	OAR 340-223-0030(1)(a)(B), contingency effective 7/1/14	0.23	30-day rolling average
	OAR 340-223-0040, effective 7/1/17	0.070	30-day rolling average

*During the initial startup of the unit, fuel oil is burned exclusively. After the initial startup period, coal is the primary fuel but some fuel oil is routinely burned to ignite individual coal pulverizers. PGE has eight pulverizers and normally runs on seven. Occasionally, a new pulverizer is put into service so that one can be taken off for maintenance. Oil use is required when the pulverizers are changed. However, the amount of fuel oil burned simultaneously with coal for the purpose of

igniting the coal pulverizers is trivial compared to the amount of coal burned and would not alter the limit for burning just coal, taking into consideration the significant figures of the standard. For example, the amount of oil typically burned in any one hour period is 480 gallons and the amount of coal is 350 tons. When the fuel rates are converted to heat inputs and put into the formula provided in 40 CFR 60.44(b), the resulting emission limit would be 0.6956 lb NO_x/mmBtu. When rounded to the significant figures of the standards, there is no change from the coal limit. Therefore, 40 CFR 60.44(b) is not included in the permit as an applicable requirement.

480 gallons of oil x 134,000 Btu/gal = 64.1 million Btu
350 tons of coal x 2000 lbs/ton x 8276 Btu/lb = 5793 million Btu
Total heat input = 64.1 + 5793 = 5857
% heat input from oil = 64/5857 x 100 = 1.09
% heat input from coal = 5793/5857 x 100 = 98.91

Ps_{nox} = [1.09(0.30) + 98.91(0.70)]/(1.09 + 98.91) = 0.6956 = 0.70

19.b. Testing requirements: Relative accuracy test audits (RATA) are required annually as part of the CEMS quality assurance program.

19.c. Monitoring requirements: Nitrogen oxide emissions are monitored with a CEMS in accordance with the Acid Rain regulations (40 CFR, part 75), NSPS regulations (40 CFR §§60.45 and 60.13), and the Department's Continuous Monitoring Manual. The CEMS records 3-hour averages for determining compliance with the NSPS limit while burning coal or oil The CEMS is also used to determine the annual average emissions for the acid rain limit. The CEMS will have to be modified to demonstrate compliance with the regional haze 30-day or 12-month rolling averages.

The CEMS measures the pollutant concentration and stack gas flow rate to calculate mass emission rates (lb/hr). The CEMS also calculates emission rates in units of the standard (lb/million Btu heat input) using fuel factors, diluent gas concentrations (%CO_2), and the appropriate equation in 40 CFR Part 75, appendix F, procedure 2. The equations in procedure 2 use different fuel factors for the different types of fuels, but instead of switching factors, PGE uses the coal factor for emission calculations while burning coal or oil. This will result in over estimating NO_x emissions when burning oil because the F factor for coal is greater than the F factor for oil. Using this approach, the actual emissions will be less than the over estimated emissions that is used for determining compliance with the standards.

20. Fuels:

20.a. Applicable requirement: The permit limits the types of fuels that can be burned in the main boiler to ASTM Grade 2 oil (distillate) or coal and incidental amounts of materials used to minimize coal fines from the coal dust suppression system. The underlying authority for this requirement is considered to be OAR 340-222-0040 because the Plant Site Emissions Limit (PSEL) and compliance monitoring methods are based on those two fuels. Changing to a different type of fuel would require a permit modification.

20.b. Testing requirement: Testing is not required because these requirements do not have any emissions limits that test results could be compared to for demonstrating compliance.

20.c. Monitoring requirement: The permit includes a requirement to monitor the type and amount of fuel burned in the boiler on an hourly basis.

21. Acid Rain

The main boiler is an affected source under Title IV of the Clean Air Act, so it is subject to the Acid Rain rules in 40 CFR Part 72 through 78. The Acid Rain permit is included as an attachment to the permit and

includes its own statement of basis. The Acid Rain permit is being renewed with this permitting action. The Acid Rain permit includes the following NO_x emissions limits:

21.a. The NO_x emissions limit is 0.46 lb/mmBtu.
21.b. The limit is based on an annual average of the CEM data required by 40 CFR Part 75.

22. Compliance Assurance Monitoring (CAM):

The main boiler is subject to the requirements of 40 CFR, Part 64 incorporated into Oregon's rules as OAR 340-212-0200 through 340-212-0280. These rules require compliance assurance monitoring for emissions units with add-on control devices that would have uncontrolled potential emissions greater than 100 tons per year if the control device were not in place. The rules are pollutant specific and only apply to those pollutants that are regulated by emissions standards or limits promulgated before November 1992, excluding the Plant Site Emissions Limit (PSEL). The main boiler does not currently have add-on control equipment for sulfur dioxide or nitrogen dioxide emissions so CAM only applies to the particulate emissions standards for which an electrostatic precipitator (ESP) is used to comply with the standards. CAM does not apply to the regional haze rules because they were adopted after 1992 and they require continuous emissions monitoring. The details of the compliance assurance monitoring have been discussed above. All other emissions units are either uncontrolled or have pre-controlled emissions less than 100 tons per year.

23. Mercury Rules:

This facility is subject to the Mercury Rules for Coal Fired Power Plants adopted in December 2006 and modified in December 2008 and June 2009 by the Environmental Quality Commission in OAR Chapter 340, Division 228. The rules originally include the federal Clean Air Mercury Rules, but those rules have sense been vacated so they were removed from DEQ's rules. The current rules contain state specific emission limits that will be effective in 2012, but have a provision for a two year extension to 2014, if necessary.

The rules require that mercury emissions be reduced by 90% or to a level of 0.60 lb/trillion Btu by 2012, or 2014, if an extension is granted. The permittee must install and certify mercury emissions monitoring equipment by January 1, 2009 and submit a plan for installing pollution control equipment by July 1, 2009. The provision for a compliance extension was included in the rule in the event that pollution control equipment is not available due to supply limitations, flyash contamination, or other circumstances that are beyond the control of the owner or operator.

PGE has installed a mercury continuous emissions monitoring system and conducted certification testing. The results of the certification test are still under review but preliminary results indicate the CEMS has met the performance certification requirements. PGE submitted a timely mercury control plan and the Department approved the plan. According to the plan, PGE will install an activated carbon injection system upstream of the ESP by 7/1/12. The system will be operated at maximum efficiency provided the carbon does not contaminate the flyash rendering it unusable as a beneficial byproduct. If the flyash is contaminated, the system will be operated at a level that will continue to reduce mercury emissions but ensure that the flyash can be used as a beneficial byproduct. PGE will then have until 7/1/14 to fully comply with the mercury standards. If the standards cannot be met by 7/1/12, PGE will be required to operate the control system as effectively as possible in the interim between 7/1/12 and 7/1/14.

PGE conducted mercury testing in August of 2006. The average results were 6.6 lbs/trillion Btu heat input and 0.038 lbs/hour. The plant only operated 4,544 hours in 2006, so the mercury emissions were 173 lbs for the calendar year, assuming the hourly emissions would be constant for each hour of operation. The mercury content in the coal can vary considerably, so it is likely that the emissions were higher or lower than this estimate. If the plant had operated the entire year, the emissions would have been approximately

333 lbs for the calendar year, again assuming that the hourly emissions would be constant. The rules require continuous or nearly continuous monitoring of emissions, so there will be less uncertainty about the actual emissions in the future.

Auxiliary boiler:

24. Visible emissions:

24.a. Applicable requirement: Visible emissions may not exceed 20% opacity for more than an aggregate of 3 minutes in any one hour in accordance with OAR 340-208-0110(2) and (3).

24.b. Testing and monitoring requirements: The auxiliary boiler is only used during plant startup, which may last for a few hours (hot start) or a few days (cold start). The permit requires that the visible emissions be monitored using EPA Method 22 for a minimum period of 6 minutes during high fire conditions. If there are no visible emissions observed, then no further monitoring is required. If visible emissions are observed for more than 18 seconds during the Method 22 observation period, then a modified EPA Method 9 is required to be conducted immediately for a period of six minutes unless any one reading is greater than 20% opacity, then the observation period must be 60 minutes or until a violation of the standard is documented, whichever period is shorter. The rationale behind this monitoring approach is that if there are no visible emissions or if the visible emissions are less than 20% opacity during a six minute observation period, then there is a reasonable assurance that the boiler is operating within the emission limits. However, if there are visible emissions and it is documented that the visible emissions exceed the limit for at least one observation period (e.g., 15 seconds), then there is the potential that the limit could be exceeded so a longer observation period is required to determine compliance.

25. Particulate Matter:

25.a. Applicable requirement: Particulate matter (PM) emissions may not exceed 0.1 gr/dscf, corrected to 50% excess air, in accordance with OAR 340-226-0210(1)(b) for new sources installed after June of 1970.

25.b. Testing requirements: Because this boiler is only used infrequently for purposes of plant startups, the maximum annual emissions are estimated to be less than 0.5 tons per year. In addition, it is unlikely that the PM emissions limit will be exceeded while burning #2 fuel oil. For these reasons, emissions tests are not required.

25.c. Monitoring requirements: Although there is no direct correlation between visible emissions and particulate matter emissions, visible emissions can be used as an indicator of good combustion practices that will also minimize particulate matter emissions. For this reason, the visible emissions monitoring described above is also used as monitoring for the PM emissions limit. In the event that there are recurring excess visible emissions, the Department may request a compliance source test be performed to demonstrate compliance with the PM limit. However, if there are no visible emissions, then there is no indication that the PM limit is being exceeded.

26. Sulfur dioxide:

26.a. Applicable requirement: The auxiliary boiler is subject to a sulfur dioxide limit of 1.4 lb/million Btu heat input as specified in OAR 340-228-0200(1)(a) for liquid fuels. This limit is based on a 2-hour average period.

26.b. Testing and monitoring requirements: While burning oil, the SO_2 limit cannot be exceeded if the fuel oil meets the specifications of ASTM Grade #2 and the sulfur content of the fuel is less than or equal to 0.5% by weight as required by OAR 340-228-0110(2). The maximum sulfur dioxide emissions while burning oil is determined as follows:

E_{SO2}	=	%S/100 x 1000000/HV x 64/32
	=	0.58 lb/million Btu heat input

Where:

E_{SO2}	=	Sulfur dioxide emissions in lb/million Btu heat input
%S	=	Maximum allowable sulfur content of the fuel oil
	=	0.5%
HV	=	Approximate heating value of #2 distillate oil (Btu/lb)
	=	17,290 Btu/lb (134,000 Btu/gallon x 7.75 lb/gallon)
64/32	=	Ratio of SO_2 and sulfur molecular weights.

Therefore, complying with the fuel oil sulfur limits provides a 25% margin of safety for complying with the stack emission limits (0.58 versus 0.8 lb/million Btu). As discussed above, PGE is required to monitor the fuel sulfur content of each type of fuel used in the boiler.

27. Fuels:

27.a. Applicable requirement: The permit limits the types of fuels that can be burned in the auxiliary boiler to ASTM Grade 2 oil (distillate) . The underlying authority for this requirement is considered to be OAR 340-222-0040 because the Plant Site Emissions Limit (PSEL) and compliance monitoring methods are based on #2 fuel oil. Changing to a different type of fuel would require a permit modification.

27.b. Testing requirement: Testing is not required because this requirement does not have any emissions limits that test results could be compared to for demonstrating compliance.

27.c. Monitoring requirement: The permit includes a requirement to monitor the type of fuel burned in the boiler on an hourly basis and the amount of fuel burned on an annual basis.

Coal processing and conveying equipment:

28. Visible emissions:

28.a. Applicable requirement: The coal processing and conveying activities at the plant, other than the coal storage pile, are subject to the visible emissions limit of 20% opacity in 40 CFR §60.252(c).

28.b. Testing and monitoring requirements: EPA Method 9 is the compliance test method as specified in 40 CFR §60.254(b)(2). However, besides an initial performance test, the NSPS does not require any routine testing or monitoring. To satisfy the Title V periodic monitoring requirements, the permittee is required to perform the monitoring described in item 14.c of this review report. The rationale behind the monitoring approach is that if there are no visible emissions leaving the plant boundary then the emissions limit is not being exceeded; but, if there are visible emissions leaving the plant boundary, then either a Method 9 test has to be conducted to demonstrate that the emission limit is not being exceeded or corrective action must be taken immediately to minimize the fugitive emissions.

Insignificant emissions units:

29. As identified earlier in this Review Report, this facility has insignificant emissions units (IEUs) that include categorically insignificant activities and aggregate insignificant emissions, as defined in OAR 340-028-0110. For the most part, the standards that apply to IEUs are for visible emissions (20% opacity limit) and particulate matter (0.1 gr/dscf limit). The Department does not consider it likely that IEUs could exceed an applicable emissions limit or standard because IEUs are generally equipment or activities that do not have any emission controls (e.g., small natural gas fired space heaters) and do not typically have visible emissions. Since there are no controls, no visible emissions, and the emissions are less than one ton per year, the Department does not believe that monitoring, recordkeeping, or reporting is necessary for assuring compliance with the standards.

29.a. At this facility, the fly ash handling system is identified as an insignificant activity. The fly ash handling system has baghouses for the control of visible and particulate matter emissions. Although these are controlled sources, the Department does not believe that monitoring, recordkeeping, or reporting is necessary for assuring compliance because the baghouses have proven to be reliable and trouble free. In addition, each baghouse is equipped with an alarm that goes off when the pressure drop across the baghouse is too high.

29.b. The coal processing and conveying activities (emissions unit CP.EU) are also insignificant activities but they are identified separately because there is an NSPS that applies to those activities.

29.c. None of the other insignificant activities are subject to NSPS or NESHAP requirements.

Other State Requirements:

30. The sulfur dioxide reporting requirements for the regional haze program in OAR 340-214-0420 are applicable to this facility. In addition, OAR 340-228-0400 through 340-228-0530 becomes effective on the program trigger date established by the procedures outlined in the SO2 Milestones and Backstop Trading Program Implementation Plan.

Other Federal requirements:

31. New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD): The requirements for fossil-fuel-fired steam generators for which construction commenced after August 17, 1971 (40 CFR Part 60, subpart D) that are applicable to the Boardman Plant are included in the permit. EPA recently issued a Notice of Violation alleging that the Boardman Plant has failed to comply with the sulfur dioxide standards of the 1978 NSPS for electric utility steam generating units due to modifications in 1998 and 2004. Additionally, plaintiffs in *Sierra Club, et al. v. PGE*, Federal District Court for the District of Oregon, Case No. CV 08-1136 HA, allege that the Boardman plant has violated NSPS and PSD modification requirements that apply to the source. The permit includes a condition acknowledging the NOV and the lawsuit, and that requires that the permit will be reopened to incorporate any new applicable requirements resulting from the NOV enforcement action or the lawsuit. Among other things, this addition to the permit is intended to make clear that the permit does not provide a shield against enforcement for the violations alleged in the NOV recently issued by the U.S. EPA to Portland General Electric, and does not provide a shield against liability that may be found by the court for the violations alleged in the lawsuit.

32. National Emission Standards for Hazardous Air Pollutants (NESHAP): Because this facility is a major source of hazardous air pollutants, the following NESHAPs are applicable:

32.a. 40 CFR Part 63, subpart ZZZZ applies to reciprocating internal combustion engines (RICE) and there is an emergency diesel generator at the plant. However, existing emergency stationary RICE do not have to meet the requirements of subpart ZZZZ and subpart A of part 63. No initial notification is necessary. [40 CFR 63.6590(b)(3)] Although not required, PGE submitted an initial notification on August 3, 2004.

32.b. 40 CFR Part 63, subpart DDDDD applies to industrial, commercial, and institutional boilers and process heaters and there is an auxiliary boiler at the plant. The auxiliary boiler meets the definition of an existing large and limited use liquid fuel unit so the only requirement is an initial notification. [40 CFR 63.7506(b)]. PGE submitted an initial notification. However, the standards have been vacated in response to a law suit. EPA is required to promulgate new standards, which will be incorporated into the permit once the rules are finalized.

32.c. Since the Clean Air Mercury Rule was vacated, EPA is now required to develop a MACT standard for mercury and possibly other hazardous air pollutants. The MACT requirements will be incorporated into the permit once the rules are promulgated or at permit renewal if there is less than 3 years left in the permit term.

32.d. Standards for gasoline dispensing facilities in 40 CFR, Part 63, subpart CCCCCC are applicable to both minor and major sources of HAPs. There is one gasoline tank at the sight, but the throughput is less than 100,000 gallons per month, so the vapor recovery requirements do not apply to the facility. The work practice requirements and requirements for a submerged fill pipe apply. In addition, there are requirements for monitoring and recording gasoline throughput and submitting a compliance status report.

33. Best Available Retrofit Technology (BART):

As discussed above, the Environmental Quality Commission adopted Best Available Retrofit Technology (BART) and reasonable progress regulations in June 2009 as required by the federal regional haze program (40 CFR 51.308). Information about this rulemaking is available at DEQ's web site.

RECORDKEEPING REQUIREMENTS

34. The permit includes requirements for maintaining records of all monitoring and testing information. These records include test results, continuous emissions monitoring data and QA/QC, parameter monitoring data, visible emissions data, the date and time of measurements; and, all corrective actions, including the date, time, and outcome.

REPORTING REQUIREMENTS

35. The permit includes requirements for submitting quarterly, semi-annual, and annual monitoring reports that include compliance certifications and semi-annual excess emissions reports. The annual monitoring report will also include operation data, emissions data, excess emission log, greenhouse gas emissions, and an emission fee report. The permittee is required to immediately notify the Department of any excess emissions and keep records of the excess emissions.

PLANT SITE EMISSION LIMITS

36. The baseline emission rate, netting basis, and Plant Site Emission Limits are as follows:

Pollutant*	**Baseline Emission Rate****	**Netting Baseline****		**Plant Site Emission Limit (PSEL)****			**PTE****
		Previous	**Proposed**	**Previous PSEL**	**Proposed PSEL**	**PSEL Increase**	
PM/PM_{10}	1056	1056	346	1056	1056	0	1056
SO_2	30450	30450	3045	30450	30450	0	30450
NO_x	17762	12687	1776	12687	11672	-1015	11672
CO	767	767	767	767	767	0	767
VOC	92	92	92	92	92	0	92
Pb	0.17	0.17	0.17	0.17	0.17	0	0.17

*Definitions of the terms used in the PSEL table are provided in appendix C of his review report.
**Tons per year.

36.a. The baseline emission rate equals the potential to emit during the baseline period because the source was permitted to construct and operate during the baseline period but had not begun operations. In previous permits, the baseline emission rate was considered to be zero for all pollutants because the first permit for the facility was not issued until December 1979 and the

facility did not actually begin operations until 1980, after the baseline period. However, the Department has recently discovered that the facility was permitted to construct and operate during the baseline period by virtue of a Temporary Permit that was issued in accordance with the rules in effect at the time. Based on this information, the Department is establishing a baseline emission rate for the facility in accordance with the definitions of *baseline emission rate* and *actual emissions* in OAR 340-200-0020. (See also the response to comments in Appendix F)

36.b. Except for NO_x, the previous netting basis for each pollutant equals the baseline emission rate because there have not been any emission reductions required by rule and there have not been any increases approved through the New Source Review regulations.

36.c. For NO_x, the previous netting basis is less than the baseline emission rate because of emission limits established by the federal Acid Rain program (0.50 lb/mmBtu in 2002 and 0.46 lb/mmBtu in 2008).

36.d. The proposed netting basis is less than the previous netting basis for most pollutants as a result of the emission limits established for the regional haze program that were adopted on June 19, 2009. The proposed netting basis equal the regulatory limit (lb/mmBtu) times the capacity of the facility (mmBtu/yr), converted to tons per year. The reductions to the netting basis were effective on the date that that the Regional Haze rules were final and effective. The PSELs will not be reduced until the compliance date(s) of the Regional Haze rules.

36.e. Except for NO_x, the proposed PSEL equals the previous PSEL because the compliance date for the regional haze requirements is not until 2011, 2014, or 2017. The PSEL for NO_x is less than the previous PSEL because the compliance date for the Acid Rain limits was in 2008.

36.f. The permit includes reductions to the PSELs based on the compliance dates specified in the regional haze regulations and the NO_x contingency requirements. The NO_x PSEL will be reduced beginning July 31, 2011. The PM and SO_2 PSELs will be reduced beginning July 31, 2014. The NO_x PSEL will be reduced further beginning July 31, 2017. Since the PSEL is an annual limit, the reductions will be phased in over 12 months beginning on the compliance date of the regulations. By July 1, 2018, all of the PSELs will be reduced to the netting basis, unless PGE makes a change that is subject to the New Source Review rules and the change is approved by the Department in accordance with OAR 340, Division 224.

36.g. The emission calculations supporting the baseline emission rate, netting basis, and PSELs are provided in Appendix A.

Components of the PSEL:

37. There are no credits or unassigned emissions for this source.

Significant Emission Rate:

38. Additional requirements must be met if a PSEL is increased by more than the significant emission rate above the netting basis after the compliance date of the regulations requiring the netting basis reductions. As shown above, the requested PSELs are not greater than the previous netting basis. Thus, no further analysis is required.

Emissions Detail Sheets:

39. The basis for the Plant Site Emissions Limits is provided in the emission detail sheets in Appendix A along with references for the emission factors used to determine emissions.

PSEL Compliance Monitoring:

40. CEMS are used to measure sulfur dioxide, nitrogen oxides, and mercury emissions from the main boiler. All other pollutant emissions are calculated using emission factors and production or process throughput

data. The emissions factors are included in the permit, but they are not by themselves enforceable limits because they are not obtained from an applicable requirement.

HAZARDOUS AIR POLLUTANTS

41. According to the emissions estimates provided by PGE in the Title V permit application and subsequent testing, this facility is a major source of hazardous air pollutants (HAP) emissions. The total potential estimated HAP emissions are 108 tons per year with hydrogen chloride and hydrogen fluoride being 53.3 and 38.3 tons; respectively. As mentioned earlier, the maximum potential mercury emissions are estimated to be about 333 lbs/year. The HAP emissions are primarily products of incomplete combustion or due to trace elements (e.g., metals) contained in the coal, therefore, the remainder of the HAP emissions are other metals contained in the coal and oil, as well as products of incomplete combustion, such as polycyclic organic material.

Toxic and Flammable Substance Usage:

42. PGE reported that they use up to 10,000 lbs of hydrogen per year.

Stratospheric Ozone Depleting Substances:

43. PGE does not manufacture, sell, distribute, or use in the manufacturing of a product any stratospheric ozone-depleting substances. Therefore, the amended 1990 Clean Air Act Sections 601-608 do not apply to the facility except that air conditioning and fire extinguishers or other equipment containing Class I or Class II substances must be serviced by certified repairmen to ensure that the substances are recycled or destroyed appropriately.

GENERAL BACKGROUND INFORMATION

44. The proposed permit is a renewal of the existing Oregon Title V Operating Permit No. 25-0016 scheduled to expire on July 1, 2006. The current Oregon Title V Operating Permit will remain in effect until this permit is issued.

45. Other permits issued or required by the Department include a Water Pollution Control Facility Permit #100189.

46. This source is located in an area that is in attainment for all pollutants.

COMPLIANCE HISTORY

47. During the last permit term, the facility was inspected on 9/12/01, 4/29/03, 7/26/05, 9/1/07, and 9/15/09 and found to be in compliance with all permit conditions.

48. There were five complaints received during the last permit cycle.

Date	Complaint	Resolution or Cause
4/1/02	Grayish smoke drifting to the northeast.	Response sent back to complainant via e-mail. ESP not used during startup – unavoidable situation.
4/4/02	PGE bombing range – stack brown/yellow plume of smoke.	Left a message for the complainant that the excess emissions were the result of a cold plant startup after being down for 2 weeks.

Date	Complaint	Resolution or Cause
4/25/02	Very dense and black smoke plume were being emitted from the stack	Plant was in start-up mode during the excess emissions. PGE notified DEQ as required.
12/16/02	Ash is settling on vehicles in the parking lot during a Christmas party It is a very slimy and milky substance.	Dust sample collected from a vehicle. One sample sent to PGE and one sample sent to DEQ lab. Two separate labs, including DEQ lab, confirm PM is not from PGE.
12/16/02	Ash from the plant is being spread all over the town of Boardman. Ash is settling on homes and automobiles.	

49. Notice of Noncompliance (NON) #ERB-2002-9362 was issued on 10/15/02 for failing to notify the Department immediately of an excess emission caused by other than a startup or shutdown event. PGE discovered this when reviewing internal excess emission reports and promptly notified the Department that the Department had not been notified of the excess emission. The violation was not referred to the Office of Enforcement and Compliance for formal enforcement action because it was not a significant violation. The excess emission (28% opacity) occurred for 1 six minute period and was due the startup of an induced fan. As corrective action, PGE ensured that the operators were aware of the requirement to immediately notify the Department of excess emissions.

50. A Warning Letter (WL) #WL-PND-AQ-2009-0024 was issued on April 16, 2009 for failure to notify the Department of excess emission within one hour and for failing to have a certified mercury continuous monitoring system installed by January 1, 2009. PGE responded by ensuring that the Department would be notified of excess emissions within one hour in the future. In addition, the mercury CEMS certification testing was performed in August 2009.

51. Excess Emissions: During the calendar years of 2001 through July of 2009, there were 150 excess emissions events. Nearly all of the events were due to startups, shutdowns, malfunctions, or scheduled maintenance when the particulate emissions control device (electrostatic precipitator) was not operated in order to avoid permanent damage caused by condensation. Eight of the events were caused by unscheduled maintenance that the operator performed to avoid a more serious excess emissions event. A summary of the excess emissions is provided in Appendix D.

Two of the excess emission events were excess NO_x emissions that occurred when it was necessary to run at low fire conditions for longer than normal during a startup to evaluate potential problems, such as turbine vibration. When running at low fire conditions, the correction factor for converting the measured emissions (ppm) to an emission rate at standard conditions (lb/MMBtu) is very large because the excess oxygen in the stack is very high. The correction factor is applied to ensure that dilution is not used to mask the emissions, but at low fire conditions, the correction is unrealistic. For this reason, the Department did not proceed with enforcement action for these excess emissions.

The remainder of the excess emission events were particulate matter excess emissions as indicated by visible emissions greater than 20% opacity. Although there is not a direct correlation between opacity and particulate emissions, opacity is used as a surrogate for monitoring excess particulate matter emissions. The permit includes two standards for particulate matter – a general and a source specific standard. The general limit (0.1 grains per dry standard cubic feet of stack gas) applies at all times, including periods of startup, shutdown, and malfunction. The source specific limit (0.04 pounds per million Btu heat input) applies at all times, except during periods of startup, shutdown, and malfunction. The source specific standard was established in accordance with the highest and best practicable treatment and control regulations in place at the time that this facility was initially permitted and it is a more stringent limit than the limit established in

the federal New Source Performance Standard for coal fired power plants. The NSPS limit is 0.1 lb/MMBtu. The source specific standard does not apply during periods of startup, shutdown, and malfunction because it takes into consideration the fact that the electrostatic precipitator (ESP) that controls particulate matter emissions cannot be operated when the stack gas is below 240° F because water and sulfuric acid in the exhaust gas will condense in the ESP and damage the components.

Although the general standard applies at all times, the Department must take into consideration the source specific standard and the reasons for why it does not apply during periods of startup, shutdown, and malfunction when evaluating whether an excess emission warrants enforcement action. Since it is not reasonable to expect that the emission unit can comply with the source specific standard during startup, shutdown, and malfunction, it would be unreasonable to expect that the emission unit would be able to comply with the general standard under those same operating conditions. Therefore, the Department treats both standards the same for purposes of determining whether enforcement is warranted for an excess emission.

One hundred thirty-nine of the excess particulate matter emission events occurred during startup, shutdown, or malfunction. As such, the Department did not proceed with enforcement action. Three were due to scheduled maintenance and the remaining eight events were not due to startups, shutdowns, or malfunctions, so they could be considered avoidable excess emissions. However, in evaluating each of these events, the Department determined that they occurred as a result of a preventive maintenance action taken by the operator to prevent a more serious excess emission from occurring. In most cases, these events lasted for 6 minutes or less. For these reasons, the Department did not proceed with enforcement action for these events.

Although the Department did not proceed with enforcement action for the 150 excess emission events that occurred during the last permit cycle, the Department does monitor the underlying reason for these events. As mentioned above, most of the excess emissions occur during startup or shutdown. Ninety-five percent of the total excess emission time was due to startup or shutdown. Startups and shutdowns are due to: 1) annual maintenance outage; 2) repairing boiler tube leaks; and, 3) operating controls that automatically trip the plant if an operating parameter is exceeded. The annual outage is necessary for maintaining the unit and tube leaks will occur from time to time. There were approximately 10 shutdowns due to tube leaks during the 6 year period. As for the plant trips, these are primarily safety measures to avoid a serious accident. All combined, the duration of the excess emissions was 3% of the total operating time.

In 2003, the Department, as the result of a joint inspection with EPA, requested that the startup/shutdown procedures be reviewed to determine if it was possible to reduce the amount of time spent during a startup. A typical cold startup prior to that time lasted about 72 hours. Upon review of the procedures, PGE found that the amount of time specified for ensuring that the ESP was warm enough to be energized may have been too conservative. As a result, they revised the procedures and startups now typically last about 48 hours. In addition, PGE found that they could switch from oil to coal sooner in the startup process, which also helped to shorten the amount of time necessary for a complete startup.

SOURCE TEST RESULTS

52. Provided below are the average test results of compliance source tests performed since 1983. In most cases, a compliance source test consists of 3 individual test runs. The opacity limit is 20% and the PM emission limit is 0.040 lbs/mmBtu).

Test Date	Gross Load (MW)	Fuel Usage (tons/hr)	Opacity (%)	PM* Emissions (lb/mmBtu)
10/26/83	494	313	1	0.006
08/15/84	353	220	2	0.006
07/17/85	519	317	9	0.010
10/02/90	537	320	3	0.012
12/18/90	487	302	2	0.023
01/29/91	534	336	4	0.012
04/03/91	534	324	4	0.011
01/22/92	542	292	5	0.036
09/09/92	541	266	4	0.009
10/20/92	544	284	4	0.009
01/26/93	539	255	10	0.017
01/24/94	542	317	7	0.016
08/24/95	541	303	6	0.007
09/19/96	541	289	7	0.023
09/18/97	527	294	4	0.006
09/10/98	550	309	3	0.008
09/10/99	555	292	8	0.015
08/23/00	595	333	7	0.014
08/15/01	578	312	7	0.017
09/10/02	581	306	3	0.010
09/11/03	585	326	6	0.009
09/23/04	616	341	3	0.012
08/03/05	611	340	3	0.010
08/31/06	611	342	1	0.010
09/11/07	613	344	4	0.007
09/11/08	597	333	4	0.007
Average	**549**	**308**	**5**	**0.012**

*Results are based on EPA Method 5 (front half particulate matter).

53. In addition to the particulate matter tests, a test for mercury emissions was conducted on August 29, 2006. The results, as expressed in different units, were 7.57 micrograms per dry standard cubic meter of stack gas, 0.038 pounds per hour, 6.6 pounds per trillion Btu heat input; and 0.00011 pounds per ton of coal burned. The unit was operating at an average of 610 Megawatts while burning 342 tons of coal per hour.

PUBLIC NOTICE

54. The initial draft of the permit renewal was released for public comment on April 27, 2006. A public hearing was held in Boardman on June 15, 2006 and in Portland on June 28, 2006. The comment period ended on July 7, 2006. A summary of the comments received during the comment period and the Department's response is provided in Attachment E. Due to a procedural error and the incorporation of the mercury requirements into the draft permit, the Department re-opened the comment period and held additional hearings on May 16, 2007 in Boardman and May 31, 2007 in Portland. The comment period ended on June 15, 2007. A summary of the comments received during the comment period and the Department's response is provided in Attachment F. Due to the significance of the comments, the Department is re-opening the comment period and holding another hearing as described below.

55. A revised draft permit was placed on public notice from April 1, 2010 to August 16, 2010. Public hearings were held in Portland on May 4, 2010 and Boardman on May 5, 2010. The Department received over 1500 comments from individuals and organizations. A summary of the comments received during the comment period and the Department's response is provided in Attachment G. The following changes were made to the permit in response to comments:

Permit Condition	Change	Basis for change
20.a	Change fuel type to western sub-bituminous and bituminous coal as specified in the original permit issued for the Boardman Plant.	PEAC comment IX and PGE response to comments.
24.e and f	Add requirements for gasoline dispensing facilities	PGE comment on May 10, 2010
31	Delete requirement to submit a mercury control plan because the requirement has been satisfied.	PGE comment
40.d	Add provision for Plant Site Emission Limit for $PM_{2.5}$	PEAC comment V.
61.d	Add gasoline throughput recordkeeping	PGE comment on May 10, 2010
89	Add requirement for initial notification for the gasoline dispensing NESHAP	PGE comment on May 10, 2010
90	Add requirement for submitting an initial compliance status report for the gasoline dispensing NESHAP	PGE comment on May 10, 2010
G11	Remove permit shield for 40 CFR Part 60, subpart Da	EPA NOV and PEAC comments I and IV.

56. A proposed permit was sent to EPA for a 45 day review period on October 22, 2010. If the EPA does not object in writing, the permit will be issued following EPA's review. Any person may petition the EPA within 60 days after the expiration of the EPA's 45-day review period to make such objection. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period.

APPENDIX A: EMISSIONS DETAIL SHEET

Unit/Device	ID	Process or Throughput		Emission Factors		Emissions (tons/yr)
		Rate	Units	Rate	Units	
Particulate matter:						
Main boiler –coal	MB.EU	5.07E+07	MMBtu/yr	0.04	lb/MMBtu	1015.0
fuel oil		1000	kgal/yr	2	lb/kgal	1.0
Auxiliary boiler –oil	AB.EU	50	kgal/yr	2	lb/kgal	0.1
Coal storage pile	CSB.EU	52	weeks/yr	20	lb/acre	26.0
Coal yard bull-dozer activity	CYB.EU	3500	hours/yr	2.78	lb/hour	4.9
Unpaved road vehicle traffic	URT.EU	20000	VMT/yr	0.927	lb/VMT	9.3
AIA	AI4.EU					
Coal yard conveyor system		3.68E+07	ton/yr	1.33E-05	lb/ton	0.24
Fly ash handling system		16863000	ton/yr	8.67E-09	lb/ton	7.31E-05
In plant coal handling conveyor system		441504	ton/yr	0.00027	lb/ton	5.96E-02
Paved road vehicle traffic:						
employee vehicles		27000	VMT/yr	0.00175	lb/VMT	2.36E-02
ash haul trucks		23000	VMT/yr	0.00815	lb/VMT	9.37E-02
water wagon		5000	VMT/yr	0.01035	lb/VMT	2.59E-02
AIA total						0.45
PM total						1056
Gaseous Pollutants:						
CO	MB/coal	3.07E+06	tons/yr	0.5	lb/ton	766.5
	MB/oil	1000	kgal/yr	5	lb/kgal	2.5
	AB/oil	50	kgal/yr	5	lb/kgal	0.1
NOx	MB/coal	5.07E+07	MMBtu/yr	0.46	lb/MMBtu	11672.1
	MB/oil	1000	kgal/yr	20	lb/kgal	10.0
	AB/oil	50	kgal/yr	20	lb/kgal	0.5
SO2	MB/coal	5.07E+07	MMBtu/yr	1.2	lb/MMBtu	30449.1
	MB/oil	1000	kgal/yr	71	lb/kgal	35.5
	AB/oil	50	kgal/yr	71	lb/kgal	1.8
VOC	MB/coal	3.07E+06	tons/yr	0.06	lb/ton	92.0
	MB/oil	1000	kgal/yr	0.2	lb/kgal	0.1
	AB/oil	50	kgal/yr	0.2	lb/kgal	0.0
Pb (w ESP)	MB/coal	5.02E+07	MMBtu/yr	1.52E-06	lb/MMBtu	0.04
(w/o ESP)	MB/coal	5.07E+05	MMBtu/yr	5.07E-04	lb/MMBtu	0.13
	MB/oil	1000	kgal/yr	1.42E-03	lb/kgal	7.10E-04
	AB/oil	50	kgal/yr	1.42E-03	lb/kgal	3.55E-05

APPENDIX B: EMISSION FACTOR DOCUMENTATION

Boiler Emission Factors:

The PM, and SO_2 short and long term emission factors for the main boiler while burning coal are equivalent to the regulatory limits (e.g., PM=0.04 lb/mmBtu, SO_2 = 1.2 lb/mmBtu). The NO_x short term emission factor is based on the NSPS limit of 0.7 lb/mmBtu and the annual emission factor is based on the Acid Rain limit of 0.5 lb/mmBtu (0.46 beginning in 2008). The lead emission factor while burning oil is based on PGE fuel analysis.

All other emissions factors for the boilers are taken from AP-42 Tables 1.1-1, 1.1-11, 1.1-13, 1.3-2, and 1.3-4.

Coal Pile Wind Erosion Emissions Estimate:

Particulate emissions from the coal pile are going to be variable from one year to the next depending on meteorological conditions and coal stocking policies. Using Section 11.2.7 of the 1993 edition of AP 42, emissions for a typical meteorological year (1988) were calculated using the following assumptions;

- Although there are five coal storage piles, they are all of similar geometry. All of the piles have height to base ratios less than 0.2 so a flat pile is assumed for calculations.
- Using conservative estimates the piles will have similar disturbance frequencies (about once per week).
- Total surface area of the coal will vary through the year but will average about 1,000,000. ft^2 (based on previous annual survey data).
- Because of the dozer operations, the threshold friction velocity will be comparable to a coal pile with scraper tracks.
- 1988 meteorological data from the Pendleton Station was used for calculations. Wind speed height was 7 meters.

AP 42 Section 11.2.7 uses a calculation which is based on summing individual emissions events over the course of a year. Each event is dependent upon the fastest wind mile observed during each disturbance interval.

$$E = k \sum_{i=1}^{N} S P_i$$

Where: E = emission factor in g/m^2 per year
k = particle size multiplier = 1.0 from AP 42
N = number of disturbance periods per year
P_i = erosion potential for ith period

From AP 42 Section 11.2.7 equation 3, for each disturbance;

$$P = 58(u^* - u_t)^2 + 25(u^* - u_t)$$

Where: P = erosion potential in g/m^2
u^* = friction velocity in m/sec
u_t = threshold friction velocity
u_t = 0.62 m/s from Table 11.2.7-2

Combining equations 4 and 5 from AP 42 Section 11.2.7 gives;

$$u^* = (0.053)(1.05)\, u^+_7$$

Where: u^+_7 = measured fastest wind mile for period

Based on this, for an emission event to occur during the disturbance interval;

$u^{+}_{7} > (0.62m/s)/[(0.053)(1.05)]$
$= 11.13$ m/s or 25 mph

Meteorological data for 1988 had 20 one week intervals with measurable emissions events. Calculating the individual events and summing yielded an annual emissions factor of 116.67 g/m^2. Using a surface area of 1,000,000 ft^2 and converting to tons, the annual emissions of particulate matter equals 11.9 tons. The maximum short term emissions occurred during the highest wind speed event (44 mph) and was equal to 5020 lbs.

It should be noted here that these calculations do not take into account the fact that the site boundary is approximately one mile east of the pile and a substantial portion of these calculated emissions will be deposited on Boardman Plant property.

Bulldozer Operation Emissions Estimate:

Particulate matter emissions for the dozer operations were calculated using the formula for bulldozer operation at western surface coal mines. From AP 42 Table 8.24-1 the emission factor for TSP <30um is;

$$E = 78.4\ s^{1.2}/M^{1.3}$$

Where: E = emission factor in lb/operating hour
s = silt content in %
M = moisture content in %

Assuming: s = 2.2% from AP 42 Table 11.2.3-1
M = 27% from 1994 Boardman monthly coal analysis
$E = 78.4\ (2.2)^{1.2}/27^{1.3} = 2.78$ lb/operating hour

1. Short term maximum daily particulate emissions would result from all three dozers operating for 24 hours;

   Maximum short term emissions = 2.78 lb/operating hr x 24 hours x 3 = <u>200 lb/day</u>

2. Annual total bulldozer operating hours from 1994 equipment maintenance records was 2518. During 1994, 2,200,000 tons of coal were burned. Total design coal consumption is 3,066,000 tons per year. Using this data to estimate dozer hours at design coal usage;

   Estimated operating hours = 2518 hr x (3,066,000/2,200,000) = 3500 hours

   Estimated annual emissions = 3500 hr x 2.78 lb/hr = 9730 lb = <u>4.87 tons of PM</u>

Again it should be noted that the site boundary is approximately one mile east of the coal storage area and the calculated emissions do not take into account the fact that a substantial portion of the emissions will be deposited on Boardman Plant property.

Unpaved Roads Particulate Matter Emissions Estimate:

From AP 42 Section 11.2.1;

$$E = k(5.9)(s/12)(S/30)(W/3)^{0.7}(w/4)^{0.5}[(365-p)/365]$$

Where:

E = emission factor in lb/vehicle mile traveled(VMT)
k = particle size multiplier
s = silt content in %
S = mean vehicle speed in mph
W = mean vehicle weight in tons
w = mean number of wheels
p = number of days >0.01 in. precipitation

for Boardman:

k = 1.0 from AP 42 Section 11.2.1.2
s = 5.0 for gravel roads from AP 42 Table 11.2.1-1
S = estimated 15 mph
W = 3 tons, vehicles are predominantly pickup trucks and vans
w = 4
p = 90 from AP 42 Figure 11.2.1-1

using this data:

$$E = 1.0(5.9)(5.0/12)(15/30)(3/3)^{0.7}(4/4)^{0.5}[(365-90)/365] = 0.927 \text{ lb/VMT}$$

Boardman VMT estimates:

Annual VMT for plant vehicles used on all roads = 50,000 based on plant records.
Assuming that VMT for the type of road is proportional to the miles of road present;
Annual VMT on unpaved roads = 50,000. x (2.5 miles unpaved / 6.5 miles total) ≈ <u>20,000</u>

Short term VMT = (20,500/) x 2 = <u>miles/day</u>

Short term emissions estimate = (0.927 lb/VMT) x (74 VMT/day) = <u>68.6 lb/day</u>

Annual emissions estimate = (0.927 lb/VMT) x (13,500 VMT/yr) x (1 ton/2000 lb) = <u>6.26 tons/yr</u>

Aggregate Insignificant Emissions Data:

I. **<u>Coal Yard Coal Handling</u>**: - The coal yard coal handling system is designed to provide coal to the in-plant coal handling system. It consists of a railcar dumper, a conveyor system, and two "stacker/reclaimers". Several different fueling scenarios are available to provide coal to the plant. Coal can be delivered directly to the plant from the railcars via the conveyor system or it can be conveyed from the railcar dumper and "stacked out" on the storage pile to be "reclaimed" and delivered to the plant at a later time. The maximum number of transfers under any of the fueling scenarios is twelve. Particulate emissions are controlled by a water based foam and chemical binder application which is sprayed on the coal during coal transfer at the dumper, "stacker/reclaimer" number 2, and/or the last conveyor transfer point. This type of dust suppression material is designed to provide control through the entire conveyor system. According to data supplied by the vendor, Betz Water Management Group, this material provides 90% reduction of particulate.

From AP 42 Section 11.2.3 for material "drop" operations;

$$E = k(0.0032)[(U/5)^{1.3}/(M/2)^{1.4}]$$

Where:

E = emission factor in lb/ton
k = particle size multiplier
U = mean wind speed in mph
M = material moisture in %

For Boardman coal yard coal handling:

k = 0.74 from AP 42 Table 11.2.3-2 for <30 um
U = 9 mph from meteorological data
M = 27% from monthly as-fired coal analysis

Therefore:

$$E = 0.74(0.0032)[(9/5)^{1.3}/(27/2)^{1.4}]$$
$$= 1.33 \times 10^{-4} \text{ lb/ton}$$

Using design coal consumption of 350 ton/hr and a maximum of twelve "drops" for the process, the short- and long-term emissions are calculated as follows:

Short-term (hourly):

= (350 ton/hr)(12 drops)
= 4200 tons dropped

Uncontrolled hourly emissions estimate;

$$= (1.33 \times 10^{-4} \text{ lb/ton})(4200 \text{ ton}) = 0.559 \text{ lb}$$

Controlled hourly emissions estimate (90% control);

= (0.559 lb)(1.0-0.9) = 0.056 lb/hr of PM

Long-term (annual):

= (350 ton/hr)(24 hr/day)(365 day/year)(12 drops)
$= 3.68 \times 10^{7}$ ton dropped

Uncontrolled annual emissions estimate;

$$= (1.33 \times 10^{-4} \text{ lb/ton})(3.68 \times 10^{7} \text{ ton}) = 4890 \text{ lb}$$

Controlled annual emissions estimate (90% control);

= (4890 lb)(1.0-0.9) = 489 lb = 0.245 ton/yr of PM

II. **<u>In-plant Coal Handling</u>** - The in-plant coal handling system is designed to receive coal from the coal yard coal handling system and deliver it to the pulverizer silos. The system consists of a distribution bin and two conveyor systems which each feed four pulverizer silos. The silos are in series and the conveyor system has splitters which can direct coal into the silo, send it on to the next silo or do both. Each coal transfer point is enclosed. Particulate emission control is accomplished by separate dust collection systems on each conveyor system. Each dust collection system draws air from inside the coal transfer enclosures and discharges the air outside the building through baghouses. The design collection efficiency is 99.9% for both baghouses.

From AP 42 Section 11.2.3 for material "drop" operations;

$$E = k(0.0032)[(U/5)^{1.3}/(M/2)^{1.4}]$$

Where:

E = emission factor in lb/ton
k = particle size multiplier
U = mean wind speed in mph
M = material moisture in %

For Boardman in-plant coal handling:

k = <u>0.74</u> from AP 42 Table 11.2.3-2 for <30 um
U = <u>1.1 mph</u> from design data in Boardman Plant Data Book Section JQ part 2.4
M = <u>27%</u> from monthly as-fired coal analysis

Therefore:

$$E = 0.74(0.0032)[(1.1/5)^{1.3}/(27/2)^{1.4}]$$
$$= 8.67 \times 10^{-6} \text{ lb/ton}$$

The plant design coal usage rate is 350 ton/hr. There are three drop points before coal starts splitting off into the silos. Assuming equal coal feed into each of the two banks of four silos the total dropped tons is;

Drop 1	350 tph
Drop 2	350 tph
Drop 3	350 tph
Silo drop 1	350 tph
Silo drop 2	262.5 tph
Silo drop 3	175 tph
Silo drop 4	<u>87.5 tph</u>
Total =	**1925 tons/hr**

<u>Short-term (hourly):</u>

Hourly tons dropped = (1925 ton/hr)

Hourly uncontrolled particulate emissions;

$$= (8.67 \times 10^{-6} \text{lb/ton})(1925 \text{ tpy}) = 0.017 \text{ lb/hr}$$

Hourly controlled emissions (99.9% control);

$$= (0.017 \text{ lb/yr})(1.0-0.999) = \underline{1.7 \times 10^{-5} \text{ lb/hr}}$$

Long-term (annual):

Annual tons dropped;

= (1925 ton/hr)(24 hr/day)(365 day/yr)
= 1.686×10^7 ton/yr

Annual uncontrolled particulate emissions;

= (8.67×10^{-6}lb/ton)(1.686×10^7tpy) = 146 lb/yr

Annual controlled emissions (99.9% control);

= (146 lb/yr)(1.0-0.999) = 0.146 lb/yr
= <0.001 ton/yr of PM

III. Flyash Handling - The flyash handling system is designed to deliver flyash from the electrostatic precipitator to storage and subsequently transfer the ash to vehicles for on site disposal or for transporting off site for use in making concrete. The system is an enclosed pneumatic transfer system with a storage dome, large storage silo, and two smaller holding silos. There are four dust collection systems with baghouses which serve to collect dust at each of the ash transfer points. The baghouses are rated at 99.9% control efficiency.

The emission formula for material drop operations is not applicable to Boardman's pneumatic flyash system. The particulate characteristics of flyash are essentially similar to dry cement so AP 42 Section 8.10 "Concrete Batching" was used for emissions factors. From AP 42 Table 8.10-2 the uncontrolled emissions factor for pneumatic unloading is 0.27 lb/ton.

Assuming:

Design coal feed rate = 350 ton/hr
Ash content of coal = 6%
Flyash content of total ash = 80%

Short-term (hourly):

Then the hourly tons of flyash generated;

= (350 ton/hr)(0.06)(0.8) = 16.8 tons

There are a maximum of three unloading operations in the flyash handling operation so hourly uncontrolled emissions;

= (0.27 lb/ton)(16.8 ton/hr)(3) = 13.6 lb

Annual controlled emissions (99.9% control)

= (13.6 lb/hr)(1.00-0.999) = 0.014 lb/hr of PM

Long-term (annual):

Then the annual tons of flyash generated;

= (350 ton/hr)(0.06)(0.8)(24 hr/day)(365 day/yr) = 147000.

There are a maximum three unloading operations in the flyash handling operation so annual uncontrolled emissions;

= (0.27 lb/ton)(147,000 ton)(3) = 119,070 lb

Annual controlled emissions (99.9% control)

= (119,070 lb/yr)(1.00-0.999) = 119 lb = 0.059 ton of PM

IV. Paved Roads - There are approximately 4 miles of paved roads on the plant site with a wide variety of vehicular traffic. The most significant vehicular traffic has been broken down into three categories for emissions calculations;

1. Light vehicles including plant and employee transportation. These vehicles have an average weight of 3 tons. The total annual vehicle miles traveled was estimated at 27,000 miles. For employee personal vehicles, this was based on the average number of employees driving each day; and, for plant vehicles, this was based on vehicle maintenance records.

2. Ash haul trucks. These trucks average 27 tons and annual vehicle mileage was estimated at 23,000. This mileage was based on the number of loads that would be hauled with the plant operating at design coal consumption (i.e., maximum ash production).

3. Water wagon used to haul water for watering the ash disposal pit. This vehicle averages 38 tons and its annual mileage was estimated at 5,000 based on an average of four loads of water per day.

From AP 42 Section 11.2.6 the emission factor for paved industrial roads;

$$E = 0.077\ I\ (4/n)\ (s/10)\ (L/1000)\ (W/3)^{0.7}$$

Where:

E = emission factor in lb/vehicle mile traveled (VMT)
I = industrial augmentation factor
n = number of lanes of traffic
s = surface material silt content in %
L = surface dust loading in lb/mile
W = average vehicle weight in tons

Paved roads all have two lanes of traffic and will be entering from unpaved areas less than half of the time so an I factor of 3.5 was used. The greatest loads on the paved roads are associated with ash hauling which is comparable to concrete batching so using AP 42 Table 11.2.6-1; s = 5.5% and L = 5.9 lb/mile

Therefore:

$$E = 0.077(3.5)(4/2)(5.5/10)(L/1000)(W/3)^{0.7}\ \text{lb/VMT}$$
$$E = 0.00175\ (W/3)^{0.7}\ \text{lb/VMT}$$

1. Plant and employee vehicles:

$$E = 0.00175\ (3/3)^{0.7} = 0.00175\ \text{lb/VMT}$$

VMT: short-term = 74 miles/day
long-term = 27,000 miles/yr

Daily emissions = 0.00175 lb/VMT x 74 miles
= 0.13 lb/day of PM

Annual emissions = 0.00175 lb/VMT x 27,000 miles
= 47.25 lb = 0.024 ton of PM

2. Ash haul trucks:

$E = 0.00175\ (27/3)^{0.7} = 0.00815$ lb/VMT

VMT: short-term = 63 miles/day
long-term = 23,000 miles/yr

Daily emissions = 0.00815 lb/VMT x 74 miles
= 0.515 lb/day of PM

Annual emissions = 0.00815 lb/VMT x 23,000 miles
= 187.5 lb = 0.094 ton of PM

3. Water wagon:

$E = 0.00175(38/3)^{0.7} = 0.01035$ lb/VMT

VMT: short-term = 13.7 miles/day
long-term = 5,000 miles/yr

Daily emissions = 0.01035 lb/VMT x 13.7 miles
= 0.14 lb/day of PM

Annual emissions = 0.01035 lb/VMT x 5,000 miles
= 51.75 lb = 0.026 ton of PM

Total Emissions:

Hourly = 0.13 + 0.515 + 0.14 = 0.785 lb/day of PM

Annual = 0.024 + 0.094 + 0.026 = 0.144 ton of PM

APPENDIX C: PSEL DEFINITIONS

Definitions of terms used in the Plant Site Emissions Limit Table

Pollutant: Plant site emission limits must be established for all regulated pollutants listed in Table 2 of OAR 340-200-0020 that are emitted above the de minimis levels defined in 340-200-0020. In limited situations, a PSEL may be established for a hazardous air pollutant for the purposes of paying fees (voluntary request by the permittee) or the source is subject to a hazardous air pollutant emission standard, limitation, or control requirement other than the PSEL. It is also possible to include the Generic PSEL for a single or combined HAPs so that the source will not be considered a major source of HAPs. This would be important for any source that has the capacity to emit greater than 10 tons of a single HAP or 25 tons of combined HAPs but wants to avoid being subject to a future MACT standard.

Other pollutant mass emission limits may be established, but these should be considered performance standards and not PSELs. For example, during the initial permitting of a fiberglass facility, the Department may establish a mass emissions limit specifically for styrene. This limit should not be considered a PSEL because there is no ambient air quality, NSPS, or Part 61 NESHAP for styrene, but styrene would be included in the PSEL for VOC. Another example would be if the Department believes it is necessary to establish an ammonia emission limit for a combustion device utilizing ammonia injection for control of NO_x. The ammonia limit should not be a PSEL because there is no ambient air quality standard for ammonia. Lead is one hazardous air pollutant for which it may be necessary to establish a PSEL because there is an ambient air quality standard for lead. However, it is not included in the table above because most sources do not emit lead. It would have to be added for the sources that do emit lead.

The annual PSEL applies to each 12 consecutive month period. Therefore, it is considered a limit on the potential to emit (PTE). Short term PSELs (e.g., lb/hr, lb/day, lb/week, lb/month) are not required, except for sources located in the Medford-Ashland AQMA must have a lb/day PSEL for PM_{10} if the emissions are greater than 5 lbs/day.

The baseline emission rate equals the actual pollutant emissions during the baseline period of 1977 or 1978. An earlier year may be used if neither 1977 nor 1978 are representative of normal operations. (Note: Each source should have already identified an appropriate baseline period, so only in very rare cases will the Department approve an alternative year.) Once established, the baseline emission rate never changes, except that it may be corrected when better information about the actual emissions during the baseline period becomes available (e.g., source test data). For new sources (those that were installed after 1978), the baseline emission rate is zero for all pollutants. If a current source operated in the baseline period, and continuously since that time, the source has a baseline emission rate whether or not it is permitted. However, a source that permanently shut down and then started up again after the baseline period would have a baseline emission rate equal to zero, even if the source is the original facility and includes the original equipment.

With the first permitting action for a source after July 1, 2001, the baseline emission rate will be frozen and recalculated only if:

- A better emission factor is established for the baseline period and approved by the Department;
- A currently operating emissions unit that the Department thought had negligible emissions is determined to have non-de minimis emissions needs to be added to the baseline emission rate; or
- A new pollutant is added to the regulated pollutant list (e.g., $PM_{2.5}$). For a pollutant that is newly regulated after 11/15/90, the initial netting basis is the actual emissions during any 12 consecutive month period within the 24 months immediately preceding its designation as a regulated pollutant. The Department will allow a prior 12 consecutive month time period to be used if it is shown to be more representative of normal source operation.

The netting basis is the baseline for determining net increases as a result of a major modification as defined in OAR 340-200-0020. The netting basis equals the baseline emission rate or the emissions that were approved during the last NSR action in accordance with OAR Chapter 340, Division 224, but only for the pollutants subject to NSR. In

addition, the netting basis must be adjusted to reflect any emission reductions required by rule, unassigned emissions, and emission reduction credits. Reductions required by rule will effect the netting basis at the time the rule is adopted, which could occur at any time during the permit term. The previous netting basis would be adjusted at the next permit renewal.

Both the previous and proposed netting basis should be shown in the columns if it is being changed due to the current permit action. If the netting basis is changed, the review report will also need a complete discussion of the NSR action or reductions due to a new rule. Normally, the netting basis is not increased with a Title V permitting action because the rules require that an ACDP be issued for any NSR/PSD action.

The previous PSEL is the PSEL approved in the previous permit. In some cases, the previous PSEL will need to be corrected if new emissions information becomes available. If there are corrections, they should be explained in the review report. The previous PSEL is provided to show whether there are any proposed PSEL increases.

The proposed PSEL is the PSEL requested by the permittee and approved by the Department. The PSEL shall equal the netting basis and be adjusted upward or downward in accordance with OAR 340-222-0041. Since the PSEL cannot include emission reductions required by a rule, the PSEL is equal to the netting basis plus any past or present requested increases approved by the Department. Requested increases are evaluated as follows:

1. If the requested increase is due to utilizing existing capacity that also existed during the baseline period (e.g., the increase is not due to a physical modification and it is not due to, or associated with, capacity that was installed after the baseline period), the permittee shall demonstrate a need and:

    - Demonstrate that the requested increase above the netting basis is less than the significant emission rate (SER); or
    - If greater than or equal to the SER, provide an assessment of the air quality impact showing that no ambient air quality standard or PSD increment will be violated in an attainment area or an offset has been obtained in a nonattainment area.

2. If the requested increase is due to a proposed physical modification or change in the method of operation (e.g., de-bottle necking that would increase the capacity of the facility), the permittee shall:

    - Demonstrate that the net emission increase above the netting baseline is less than the significant emission rate (SER);
    - If greater than or equal to the SER and the source is not a federal major source, provide an assessment of the air quality impact showing that no ambient air quality standard or PSD increment will be violated in an attainment area or an offset has been obtained in a nonattainment area; or
    - If greater than or equal to the SER and the source is a federal major source, satisfy the requirements of the NSR rules in OAR Chapter 340, Division 224.

3. If the requested increase is due to both utilizing existing capacity and a physical modification, the increases shall be tracked separately as shown in the significant emissions rate table. If the total increase is greater than the SER, but the increase due to a physical modification is less than the SER, the source shall satisfy the requirements of item 1 above.

4. PSELs shall not be established which allow emissions in excess of those allowed by any applicable federal or state regulation in accordance with OAR 340-222-0043(1). Note that reductions required by rule do not affect the baseline emission rate, but they will affect the netting basis.

PSEL increase means the difference between the proposed PSEL and the previous PSEL. This can be a positive or negative number. This information is primarily for the purpose of keeping the public informed of any recent changes in the allowable emissions of a source. The information is not used to determine if an SER has been exceeded. SER exceedances are determined as the difference between the proposed PSEL and the netting basis.

Capacity means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Capacity is necessary for establishing the PSEL and unassigned emissions if the current capacity is less than the netting basis.

Potential to Emit (PTE) means the lesser of the capacity of a source or the maximum allowable emissions taking into consideration any physical or operational limitation, including the PSEL, air pollution control equipment and restrictions on hours of operation or on the type and amount of material combusted, stored, or processed, if the limitation is enforceable by the DEQ and EPA.

PTE is used to determine which type of permit is required. If the PTE is less than the Title V major source threshold levels, the source would be required to obtain an ACDP. If the PTE is greater than the Title V major source threshold levels, the source would be required to obtain an Oregon Title V Air Operating Permit.

The PTE does not affect the PSEL and the PSEL shall not be reduced solely because of the PTE. However, it is not expected that any previous action that decreased PSELs to equal the PTE be reversed.

Unassigned emissions are that portion of the baseline emission rate that is greater than the source's current capacity, excluding any credits. The source's current capacity can be thought of as the source's potential emissions at the maximum possible production levels without considering the PSEL.

Emission Reduction Credits are established by OAR 340, Division 268. Emission reduction credits are a portion of the total PSEL and should, therefore, not exceed the PSEL. Credits need to be identified separately in the permit with the terms (e.g., expiration date) of the credit clearly stated. Note, the baseline emission rate is not affected by credits and the PTE of a source would, by definition, not include any credits, whether transferred or banked.

Emission reduction credits, whether from shutdowns, curtailments, or over-control, are available for external offsets for a period of two years from the date of the actual emissions reduction.. Emission reduction credits may also be banked for a specified period up to ten years. Requests for emission reduction credit banking shall be submitted to the Department prior to or within one year following the actual emissions reduction.

If credits are not used either internally or externally within the banked period, they are no longer available to the source and will be removed from the permit.

Significant Emission Rate Table:

The SER (significant emission rate) for each pollutant is defined in OAR 340-200-0020. Pollutant emission increases above the SER are subject to additional requirements. For PSEL increases that do not involve a physical modification, an air quality assessment is required to show that there will not be a violation of an ambient air quality standard or PSD increment. For PSEL increases that are the result of a physical modification, the permittee shall comply with the NSR requirements in OAR Chapter 340, Division 224.

The requested increase is the difference between the proposed PSEL and the previous netting baseline less any credits and reductions required by rule since the last permit action. The requested increase is also divided into portions that are due to utilization of capacity that existed in the baseline period and/or physical modifications at the facility as discussed in the Proposed PSEL section above. If the requested increase is greater than the SER, the review report will have to include a discussion of why the Department is approving the increase. This could be the results of an air quality assessment or NSR review, depending on the reason for the increase.

APPENDIX D: SUMMARY OF EXCES EMISSIONS

Excess Emissions Summary:

Year	Events	Startup Shutdown	Malfunction	Scheduled Maintenance	Other	Operating Time (hours)	EE Time (hours)	Percent of Operating Time
2001	11	7	3	0	1	8195	171	2.1%
2002	21	18	3	0	0	7121	413	5.8%
2003	14	6	7	0	1	7936	130	1.6%
2004	18	13	5	0	0	6578	230	3.5%
2005	17	13	3	0	1	6372	158	2.5%
2006	23	12	6	0	5	4544	168	3.7%
2007	16	12	4	0	0	7787	68	0.9%
2008	21	15	5	1	0	5211	144	2.8%
2009	9	6	1	2	0	2449	148	6.0%
Total	**150**	**102**	**37**	**3**	**8**	**56193**	**1630**	**2.9%**
Max	23	18	7	2	5	8195	413	6.0%
Min	9	6	1	0	0	2449	68	0.9%
Avg.	17	11	4	0	1	6244	181	3.2%

2001 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
1/26/2001	VE	0.1	36	%	malfunction	"A" ID fan trip	M
1/26/2001	VE	0.1	8	%	malfunction	"B" ID fan trip	M
2/25/2001	VE	10	94	%	shutdown/startup	Plant trip and restart	S
2/27/2001	VE	9	94	%	shutdown/startup	Plant trip and restart	S
6/8/2001	VE	71	94	%	startup		S
7/18/2001	VE	0.2	38	%	maintanance	ESP row 6 shutdown for repairs	O
8/6/2001	VE	0.1	36	%	malfunction	ID fan trip	M
8/23/2001	VE	1	77	%	shutdown		S
8/24/2001	VE	31	95	%	startup		S
11/9/2001	VE	1	24	%	shutdown		S
11/12/2001	VE	47	94	%	startup		S

	Hours	Percent
Hours of operation	8195	93.55% of total possible hours
Total excess emissions	171	2.08% of operating hours
Startup/shutdown excess emissions	170	2.07% of operating hours
Malfunction excess emissions	0.3	0.00% of operating hours
Other excess emissions	0.2	0.00% of operating hours

VE = visible emissions
ESP =-electrostatic precipitator
ID = induced draft

2002 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
3/2/2002	VE	1	39	%	shutdown	tube leak	S
3/7/2002	VE	41	93	%	startup		S
3/20/2002	VE	1	14	%	shutdown	tube leak	S
3/25/2002	VE	28	93	%	startup/shutdown	aborted startup - drum manway leak	S
3/26/2002	VE	10	93	%	startup/shutdown	aborted startup - turbine valve malfunction	S
3/29/2002	VE	42	93	%	startup		S
3/31/2002	VE	1	29	%	shutdown	Plant trip due to transmission line fault	S
4/2/2002	VE	38	93	%	startup		S
4/11/2002	VE	1	23	%	shutdown	steam drum level indication problem	S
4/15/2002	VE	6	93	%	startup/shutdown	aborted startup for economic reasons	S
4/22/2002	VE	52	93	%	startup		S
5/19/2002	VE	33	93	%	shutdown/startup	500 kV line repair	S
5/28/2002	VE	0.1	28	%	malfunction	ID fan startup	M
5/31/2002	VE	1	21	%	shutdown	annual maintenance	S
6/30/2002	VE	23	77	%	startup	aborted	S
7/2/2002	VE	12	87	%	startup	aborted	S
7/9/2002	VE	84	94	%	shutdown		S
7/22/2002	VE	34	94	%	shutdown/startup		S
8/24/2002	VE	0.1	36	%	malfunction	ID fan tripped	M
9/3/2002	VE	0.1	41	%	malfunction	ID fan tripped	M
12/15/2002	VE	5	94	%	shutdown/startup	plant trip	S

	Hours	Percent
Hours of operation	7121	81.3%of total possible hours
Total excess emissions	413	5.8%of operating hours
Startup/shutdown excess emissions	413	5.8%of operating hours
Malfunction excess emissions	0.3	0.0%of operating hours
Other excess emissions	0.0	0.0%of operating hours

2003 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
1/8/2003	VE	1	9	%	shutdown		S
1/11/2003	VE	39	93	%	startup		S
1/31/2003	VE	19	93	%	shutdown/startup	hydraulic leak repair	M
2/3/2003	VE	0.1	59	%	malfunction	"A" ID fan trip	M
3/1/2003	VE	0.1	35	%	startup	"D" ID fan trip	M
3/16/2003	VE	0.2	27	%	malfunction	"C" ID fan maintenance	O
5/30/2003	VE	1	12	%	shutdown	annual maintenance	S
6/27/2003	VE	40	91	%	startup		S
8/5/2003	VE	0.1	34	%	malfunction	"A" ID fan tripped due to bad control power supply	M
9/22/2003	VE	0.1	81	%	malfunction	"A" and "B" ID fans tripped when the breaker to their coolant drives opened due to an HVAC system problem	M
9/22/2003	VE	0.1	28	%	malfunction	"A" ID fan tripped due to "sticky" contact	M
12/14/2003	VE	5	93	%	shutdown/startup	plant tripped due to an instrument malfunction during routine tubine vlave test	M
12/28/2003	VE	1	12	%	shutdown	tube leak	S
12/31/2003	VE	23	93	%	startup		S

	Hours	Percent
Hours of operation	7936	90.6%of total possible hours
Total excess emissions	130	1.6%of operating hours
Startup/shutdown excess emissions	105	1.3%of operating hours
Malfunction excess emissions	24.5	0.3%of operating hours
Other excess emissions	0.2	0.0%of operating hours

2004 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
1/16/2004	VE	5	93	%	shutdown/startup	plant trip on main turbine thrust bearing wear indication	M
1/28/2004	VE	9	93	%	shutdown/startup	repair broken insulatators	M
4/30/2004	VE	1	81	%	shutdown	annual maintenance	S
7/23/2004	VE	92	94	%	startup	aborted due to primary air (PA) fan high vibration	S
7/28/2004	VE	33	95	%	startup		S
7/30/2004	VE	1	8	%	shutdown	PA fan work	S
8/1/2004	VE	17	99	%	startup		S
8/6/2004	VE	1	7	%	shutdown	PA fan work	S
8/7/2004	VE	16	99	%	startup		S
8/12/2004	VE	0.1	41	%	malfunction	"A" ID fan tripped due to coolant problem	M
8/30/2004	VE	1	1	%	shutdown	tube leak	S
8/31/2004	VE	12	99	%	startup		S
9/26/2004	VE	8	99	%	shutdown/startup	plant trip from indicated transmission line fault	M
11/8/2004	VE	1	12	%	shutdown	tube leak	S
11/10/2004	VE	12	100	%	startup		S
11/17/2004	VE	1	58	%	malfunction	two ID fan and one FD fan tripped due to control problems	M
12/24/2004	VE	1	13	%	shutdown	tube leak	S
12/26/2004	VE	19	100	%	startup		S

	Hours	Percent
Hours of operation	6578	75.1%of total possible hours
Total excess emissions	230	3.5%of operating hours
Startup/shutdown excess emissions	207	3.1%of operating hours
Malfunction excess emissions	23.1	0.4%of operating hours
Other excess emissions	0	0.0%of operating hours

2005 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
3/22/2005	VE	0.1	29	%	other	ESP maintenance	O
3/27/2005	VE	1	8	%	shutdown	tube leak	S
3/30/2005	VE	14	100	%	startup		S
4/29/2005	VE	1	0	%	shutdown	annual maintenance	S
5/27/2005	VE	34	100	%	startup		S
7/18/2005	VE	7	100	%	shutdown/startup	plant trip due to main transformer deluge	M
7/21/2005	VE	0.1	35	%	malfunction	ID fan trip	M
7/22/2005	VE	1	20	%	shutdown	tube leak	S
7/23/2005	VE	13	100	%	startup		S
8/19/2005	VE	1	10	%	shutdown	tube leak	S
8/21/2005	VE	16	100	%	startup		S
10/23/2005	VE	1	100	%	shutdown	turbine vibration, restart aborted	M
10/27/2005	VE	3	73	%	startup	aborted/generator problem	S
10/31/2005	VE	35	100	%	startup	aborted/turbine vibration	S
11/2/2005	NOX	1	0.72	lb/MMBtu	startup	aborted/turbine vibration	S
11/16/2005	VE	29	100	%	startup		S
11/18/2005	VE	1	100	%	shutdown	cracked low pressure turbine rotor	S

	Hours	Percent
Hours of operation	6372	72.7%of total possible hours
Total excess emissions	158	2.5%of operating hours
Startup/shutdown excess emissions	150	2.4%of operating hours
Malfunction excess emissions	8.1	0.1%of operating hours
Other excess emissions	0.1	0.0%of operating hours

2006 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
2/5/2006	VE	25	88	%	startup	aborted/generator problem	S
5/15/2006	VE	11	85	%	startup	aborted/hydrogen cooler leak	S
5/16/2006	VE	34	100	%	startup		S
5/22/2006	VE	17	100	%	shutdown/startup	install turbine balance weight	O
5/24/2006	VE	10	100	%	shutdown/startup	install turbine balance weight	O
5/24/2006	NOX	4	0.73	lb/MMBtu	startup		S
5/25/2006	VE	1	8	%	shutdown	plant shutdown for economic reasons	S
5/31/2006	VE	24	100	%	startup		S
6/1/2006	VE	5	100	%	startup	aborted/turbine vibration	M
6/29/2006	VE	16	100	%	startup		S
6/30/2006	VE	9	100	%	shutdown/startup	install turbine balance weight	O
6/30/2006	VE	12	100	%	shutdown/startup	install turbine balance weight	O
7/1/2006	VE	1	53	%	malfunction	ID fan tripped	M
7/19/2006	VE	6	100	%	malfunction	plant tripped due to computer malfunction	M
7/27/2006	VE	1	25	%	malfunction	ID fan tripped during coolant pump cleaning	M
9/23/2006	VE	1	71	%	shutdown	tube leak	S
9/27/2006	VE	14	100	%	startup		S
10/17/2006	VE	0.1	33	%	other	ESP row 6 TRs shudtown for maintenance w/o shutting off rappers	O
10/28/2006	VE	1	14	%	shutdown	boiler drain valve leak repair	M
10/29/2006	VE	21	100	%	startup	aborted due to exciter transformer failure	M
10/31/2006	VE	17	100	%	startup		S
11/25/2006	VE	2	99	%	shutdown	tube leak	S
11/26/2006	VE	15	100	%	startup		S

	Hours	Percent
Hours of operation	4544	51.9%of total possible hours
Total excess emissions	168	3.7%of operating hours
Startup/shutdown excess emissions	164	3.6%of operating hours
Malfunction excess emissions	35	0.8%of operating hours
Other excess emissions	48	1.1%of operating hours

2007 Excess Emissions:

Date	Pollutant	Duration (hours)	Magnitude	Units	Category	Reason	Code
1/26/2007	VE	1	15	%	shutdown	tube leak	S
1/27/2007	VE	17	100	%	startup		S
2/15/2007	VE	1	9	%	shutdown	tube leak	S
2/19/2007	VE	16	100	%	startup		S
3/29/2007	VE	1	9	%	shutdown	economic reasons	S
4/5/2007	VE	16	100	%	startup		S
5/4/2007	VE	1	1	%	shutdown	scheduled annual maintenanc outage	S
5/29/2007	VE	33	100	%	startup		S
7/24/2007	VE	312	100	%	shutdown	unit trip	S
8/4/2007	VE	1398	100	%	shutdown		S
9/9/2007	VE	18	43	%	malfunction	fire in ID fan controls	M
9/10/2007	VE	18	100	%	malfunction	ID fan controls malfunctioned	M
9/12/2007	VE	12	23	%	malfunction	ID fan trip	M
9/23/2007	VE	456	100	%	shutdown		S
10/12/2007	VE	756	100	%	malfunction	plant trip due to PA fan malfunction	M
10/15/2007	VE	1020	100	%	startup		S

VE = visible emissions
ESP = electrostatic precipitator
ID = induced draft
PA= primary air

	Hours	Percent
Hours of operation	7787	177.8%of total possible hours
Total excess emissions	68	0.9%of operating hours
Startup/shutdown excess emissions	55	0.7%of operating hours
Malfunction excess emissions	13	0.2%of operating hours
Other excess emissions	0	0.0%of operating hours

2008 Excess Emissions:

Date	Pollutant	Duration (minutes)	Magnitude	Units	Category	Reason	Code
1/6/2008	VE	461	82	%	shutdown		S
1/7/2008	VE	719	100	%	startup		S
1/9/2008	VE	329	9	%	shutdown		S
1/12/2008	VE	635	100	%	startup		S
1/13/2008	VE	311	9	%	shutdown		S
1/31/2008	VE	5	40	%	malfunction	ID fan malfunction	M
2/9/2008	VE	419	65	%	shutdown	unit trip	S
3/1/2008	VE	365	100	%	shutdown		S
3/2/2008	VE	929	100	%	startup		S
3/15/2008	VE	431	100	%	shutdown	unit trip	S
3/18/2008	VE	6	37	%	malfunction	ID fan malfunction	M
4/24/2008	VE	??	100	%	scheduled maintenance	maintenance activities during annual maintenance outgage	SM
7/4/2008	VE	624	100	%	shutdown		S
7/6/2008	VE	996	100	%	startup		S
8/13/2008	VE	6	40	%	malfunction	ESP row 6 rapper malfunction	M
8/16/2008	VE	12	98	%	malfunction	ID fan malfunction	M
9/19/2008	VE	492	100	%	shutdown		S
9/21/2008	VE	912	100	%	startup		S
9/29/2008	VE	252	100	%	shutdown		S
10/1/2008	VE	708	100	%	startup		S
12/29/2008	VE	6	62	%	malfunction	ESP row 6 TR trip	M

	Hours	Percent
Hours of operation	5211	119.0%of total possible hours
Total excess emissions	144	2.8%of operating hours
Startup/shutdown excess emissions	143	2.7%of operating hours
Malfunction excess emissions	1	0.0%of operating hours
Schedule maintenance	0	0.0%of operating hours
Other excess emissions	0	0.0%of operating hours

2009 Excess Emissions through July 1, 2009:

Date	Pollutant	Duration (minutes)	Magnitude	Units	Category	Reason
1/4/2009	VE	348	100	%	malfunction	power failure on north ESP transformer
1/6/2009	VE	12	68	%	scheduled maintenance	Power to north ESP shutoff to reroute a more reliable fix
1/30/2009	VE	656	100	%	shutdown	tube leak
1/31/2009	VE	836	100	%	startup	
4/3/2009	VE	2048	100	%	scheduled maintenance	maintenance activities during annual maintenance outage
6/14/2009	VE	1593	90	%	startup/shutdown	startup after annual outage, startup aborted due generator problems
6/19/2009	VE	2365	85	%	startup	
6/28/2009	VE	358	56	%	shutdown	shutdown to test generator
6/29/2009	VE	669	88	%	startup	startup aborted due to high vibration in generator

	Hours	Percent
Hours of operation	2449	55.9%of total possible hours
Total excess emissions	148	6.0%of operating hours
Startup/shutdown excess emissions	108	4.4%of operating hours
Malfunction excess emissions	6	0.2%of operating hours
Schedule maintenance	34	1.4%of operating hours
Other excess emissions	0	0.0%of operating hours

APPENDIX E: RESPONSE TO PUBLIC COMMENTS (4/27/06 – 7/7/06)

Note: These are the responses to comments received during the pubic comment period in 2006. These responses were previously released to the public in 2006. Items in bold are updates based on recent rule changes.

Introduction

Portland General Electric (PGE) is required to have an Oregon Title V Operating Permit for the coal fired power plant located near Boardman, Oregon. The Title V permit was first issued on October 22, 1996. Title V permits are required to be renewed every 5 years to ensure that the permits contain the latest requirements and provide an opportunity for public involvement. The Title V permit for the Boardman plant was last renewed on July 1, 2001.

The comment period for the proposed permit renewal was opened on April 27 and extended to July 7, 2006. Public hearings were held in Boardman on June 15 and in Portland on June 28 at the request of the Northwest Environmental Defense Center (NEDC). The Department received comments from over 100 individuals during the comment period and at the public hearings. Many of the individuals who provided comments represented the following special interest groups:

- Association of Oregon Industries
- Columbia Riverkeeper
- Friends of the Columbia Gorge
- Jobs with Justice
- Morrow County
- Northwest Environmental Advocates
- Northwest Environmental Defense Center (NEDC)
- Pacific Environmental Advocacy Center (PEAC)
- Portland General Electric (PGE)
- Oregon Center for Environmental Health
- Oregon Global Warming Action Network (OGWAN)
- Oregon Physicians for Social Responsibility
- Oregon State Public Interest Research Group (OSPIRG)
- Oregon Toxics Alliance
- Sierra Club
- Yakama Nation

The complete text of each person's comments is provided on DEQ's website at http://www.deq.state.or.us/er/PGE.htm. Provided below is a summary of the comments and the Department's response.

Require immediate controls for SO_2, NO_x, and Hg:

Most people requested the DEQ add requirements to the Title V permit for reducing pollutant emissions as soon as possible. They expressed concern that pollutant emissions from the plant cause or contribute to one or more of the following:

- Adverse health effects
- Damage to eco-system (acid rain, low pH)
- Contamination of fish and wildlife (mercury deposition)
- Impairment of visibility in the Columbia River Gorge National Scenic Area
- Impairment of visibility in Class I wilderness areas and national parks
- Global warming
- Damage to Native American rock images

- Consumption of Umatilla and Morrow County airshed

Written comments: 1, 2, 3, 4, 5, 6, 8, 9, 10, 11, 12, 13, 15, 16, 17, 19, 20, 21 (PEAC VIII, X, XI)
Oral comments: b, c, d, e, g, h, I, k, l, m

Response:

The Department agrees that these are significant issues, however, Title V is not a program that establishes new requirements for a specific facility. Requirements are established by rule or within pre-construction permits in accordance with the Oregon State Implementation Plan. Title V is a federally-mandated permitting program that consolidates all applicable requirements into one document and provides for adequate monitoring, recordkeeping, and reporting to assure compliance with the requirements. [Federal Clean Air Act 1990 Amendments and 40 CFR Part 70]

The Department is developing two rules that will establish new requirements for the PGE Boardman facility. A rule for reducing mercury from coal fired power plants is scheduled for action by the Environmental Quality Commission (EQC) in December of 2006 and a rule for establishing Best Available Retrofit Technology (BART) for reducing emissions of visibility impairing pollutants (e.g., SO_2, NO_x, and fine particulate matter) is scheduled for EQC action in the Fall of 2007. If these rules are adopted, the requirements will be incorporated into the Title V permit. If there is more than 3 years left in the permit term, the requirements will be incorporated immediately following adoption of the new rules. If there is less than 3 years left in the permit term, the requirements will be incorporated at the next permit renewal. In either case, PGE Boardman must comply with the new requirements as established by rule. **[Note: The mercury and BART rules have been finalized and the requirements have been incorporated into the draft permit]**

Although the permit will not be modified during this permit renewal to include additional controls for pollutants other than mercury, the Department has required in previous permitting actions that air dispersion modeling be conducted to determine whether the emissions would cause an exceedance of the national ambient air quality standards (NAAQS) for particulate matter, sulfur dioxide, nitrogen oxides, and carbon monoxide. The NAAQS are established by EPA to protect both public health and public welfare. Modeling was performed when the facility was first permitted and then repeated in 1995. The results of the modeling have shown that the emissions from the plant are not expected to cause an exceedance of the NAAQS. In addition, ambient monitoring was conducted at a site near the plant that the model predicted would have the highest impacts. The measured emissions were well below the NAAQS.

Incomplete application (compliance certification incorrect)

Several people commented that the application for permit renewal was incomplete because the responsible official certified that the source is operating in compliance with the permit when, in fact, there have been numerous excess emissions during the past permit term. In addition, there were comments that the source has not complied with Prevention of Significant Deterioration (PSD) requirements, so the application should have included a compliance schedule.

Written comments: 3, 7, 21 (PEAC V.A)
Oral comments: g, n

Response:

With regards to excess emissions, the permit requires PGE to notify the Department of excess emissions immediately upon occurrence and summarize the excess emissions in the semi-annual compliance certifications (SACC). The Department reviews the excess emissions and determines whether enforcement action is warranted based on whether the excess emissions were avoidable or unavoidable along with other considerations. If the Department does not take enforcement action and PGE follows the requirements for notifying the Department of the excess emissions, then PGE may certify compliance with the conditions of the permit when submitting the application for a permit

renewal. If PGE could not comply with an emission limit or standard under normal operating conditions, then PGE would have to certify non-compliance and include a compliance schedule in the application.

With regards to PSD, please read the response provided below.

Applicable requirements:

The permit shield (condition 74) is too broad and it should not apply to PSD:

Written comments: 21(PEAC III.D)
Oral comments: g, n

Response:

As pointed out in the comment, EPA has also expressed this concern and the Department intends to make changes to the model permits and procedures for providing a permit shield for non-applicable requirements. If a requirement is obviously not applicable to a facility, a permit shield is not necessary. The permit shield will be used for those requirements that are applicable to emission units of the type located at the source, but for one reason or another are not applicable to the specific emissions units located at the source. For instance, subpart Db of the New Source Performance Standards (NSPS) includes emission limits for fossil fuel fired steam generating units manufactured after June 19, 1984. If a facility has a fossil fuel fired steam generating unit manufactured prior to the applicable date of the NSPS, then the permit will include a shield for those requirements. However, the permit will not include a shield for the NSPS general requirements that pertain to modifications of existing facilities that could make the facility an affected facility. If a facility is modified so that it becomes an affected facility, the permit would be modified to include the requirements of the NSPS and the permit shield would be removed or narrowed in scope as may be applicable.

Like the general provisions of the NSPS, the Department does not provide a shield from other rules that could be triggered at anytime. These include the construction approval rules in division 210, PSEL rules in division 222, New Source Review (including PSD) rules in division 224, and the general provisions of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) contained in 40 CFR Parts 61 and 63.

1975 PSD exemption: Several people commented that PGE was not exempt from PSD regulations when it commenced construction in the late 1970's.

Written comments: 1, 3, 7, 15, 21 (PEAC III)
Oral comments: c, g, n

Response:

This issue was raised when the first Title V permit was issued to PGE in 1996. The comments generally state that in May 1975 the U.S. Environmental Protection Agency (EPA) illegally exempted the Boardman plant from EPA's 1974 Prevention of Significant Deterioration (PSD) regulations, and that even if the 1975 exemption was correct, the August 7, 1977 statutory PSD amendments were more strict than the 1974 regulations and required the Boardman plant to undergo PSD at that time. The department disagrees for the following reasons.

May 16, 1975 Exemption from PSD under EPA's 1974 PSD Regulations

By letter dated May 16, 1975, EPA exempted the Boardman plant from PSD. This letter stated that the Boardman plant, which had not yet been built, had nevertheless "commenced" construction within the meaning of 40 CFR 52.21(b)(7) because PGE had entered into a "binding agreement or contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction." The PSD program at that time applied only to sources which had not commenced construction prior to June 1, 1975. EPA reviewed documents relating to PGE's

agreement with Westinghouse to purchase a turbine that likely cost tens of millions of dollars (though the letter did not specify the price).

EPA subsequently changed its interpretation of the relevant regulations regarding commencement of construction as explained in the two "Strelow" memos (authored by EPA employee Roger Strelow) that were published December 18, 1975 and April 21, 1976. The memos stated that commencement of construction could include, in case-by-case determinations, sources that had not commenced on-site construction, but had executed on-site construction contracts which would cause unavoidable, substantial loss if cancelled, or had not contracted for on-site construction but had executed contracts for unique, site-specific facilities or equipment that irrevocably committed the source to a specific site.

EPA's changed interpretation of the regulations regarding commencement of construction was at issue in *Montana Power Co. v. EPA*, 608 F.2d 334 (9th Cir. 1979). Commenters state that the Ninth Circuit's decision in that case proves that EPA wrongly exempted the Boardman plant from PSD in May of 1975. In the case, EPA declined to exempt a Montana Power power plant from PSD in May 1976. The facts of the Montana Power and Boardman situations are similar - in both cases, the sources had not begun on-site construction by June 1, 1975, but had executed agreements to purchase very expensive turbines (in the tens of millions of dollars). The court recognized EPA's exemption of the Boardman plant under similar circumstances, but nevertheless upheld EPA's decision to require the Montana Power plant to undergo PSD. The court reasoned that Montana Power would not have incurred a substantial loss from canceling its contracts because, although it would have lost millions of dollars, the loss represented only 2.8% of the total project cost. Further, the court rejected the argument that EPA's decision was arbitrary and illegal due to EPA's previous exemption of the similar Boardman plant from PSD. The court deferred to EPA's ability to change its interpretation of its regulations in light of its experience over time. Thus the Ninth Circuit has upheld EPA's ability to apply its PSD regulations regarding commencement of construction differently to the similar Boardman and Montana Power plants because EPA changed its interpretation of those regulations with the Strelow memos.

Despite the court's holding, commenters point to a statement in the case that "EPA has since admitted it mistakenly exempted [the Boardman plant] from PSD review and permitting on the basis of a turbine generator contract." They state that EPA has admitted that it incorrectly applied its 1974 PSD regulations, and that therefore DEQ (which has since replaced EPA as the PSD implementing agency in Oregon) should apply PSD to Boardman now. However, on the basis of the Ninth Circuit's written opinion alone, it is unclear if EPA actually admitted to a mistake. For example, the trial court opinion stated somewhat differently that EPA claimed that the Boardman decision predated the Strelow memos and was an "incorrect" interpretation of the regulations. *Montana Power Co. v. EPA*, 429 F.Supp. 683, 700 (D. Mont. Jan. 27, 1977). Thus it is unclear what exactly EPA said.

EPA's subsequent lack of any follow up or further statements that it mistakenly exempted the Boardman plant from PSD tend to undermine commenters' interpretation of the courts' statements in the Montana Power case. For example, a July 14, 1981 letter from EPA to PGE mentioned EPA's previous Boardman exemption without stating that it was mistaken, albeit the letter primarily concerned a different air quality topic and did not specifically analyze the PSD exemption. Moreover, EPA did not revisit the exemption issue anytime between the Montana Power trial in 1976 and EPA's PSD delegation to DEQ on August 13, 1982 (47 Fed. Reg. 35,191). Based upon its actions, it appears that EPA did not conclude that it made a mistake. Furthermore, at the time of the May 1975 letter, EPA's decision was apparently consistent with its interpretation of the 1974 PSD regulations.

<u>PSD Under the August 7, 1977 Clean Air Act Amendments</u>

After EPA exempted the Boardman plant from the 1974 PSD regulations, Congress enacted PSD into the Clean Air Act as part of its August 7, 1977 amendments. The statutory PSD program applied as of the date it was enacted, was generally more strict that the regulations, and in particular defined "commencement" more strictly. Thus the Boardman plant could have been exempt under the 1974 regulations but could have triggered PSD under the 1977 amendments to the Clean Air Act. Among the requirements for commencing construction under the statute, a source had to obtain all necessary preconstruction approvals or permits by August 7, 1977, which the Montana Power court interpreted to include state air quality permits (not just a site certification permit). Thus although PGE had acquired

a March 24, 1975 site certificate from predecessor of the Oregon Energy Facility Siting Council, commenters state that it did not obtain all necessary approvals or permits until it received its Air Contaminant Discharge Permit (ACDP) from DEQ on December 6, 1979. As a result, commenters state that PGE did not commence construction under the statute by August 7, 1977, and the Boardman plant therefore triggered PSD under the statute.

The Boardman plant's March 24, 1975 site certificate lists permits necessary for construction or operation, and that list includes an ACDP for operation (but not construction). Because the ACDP wasn't required for construction, the Boardman plant did not require that permit to have commenced construction. **[Note: A Temporary ACDP issued in April 1977 authorizing construction and operation of the facility in accordance with the regulations in place at the time. See also appendix F.]**

Modifications that may have triggered PSD since the plant was first built: Several people commented that even if the Boardman plant was not subject to PSD initially, there have been changes at the facility that could be considered major modifications subject to PSD review.

Written comments: 21 (PEAC III.D)
Oral comments: g, n

Response:

The prevention of significant deterioration (PSD) rules are triggered when there is a major modification at an existing facility. "Major modification" is defined in OAR 340-200-0020. The portion of the definition that applies to PGE Boardman is as follows:

Major modification means any physical change or change in operation of a source that results in the following for any regulated air pollutant:

(c) For new or modified major sources that were permitted to construct and operate after the baseline period and were not subject to New Source Review, a major modification means:

(A) Any change at a source, including production increases, that would result in a Plant Site Emission Limit increase of 1 ton or more for any regulated pollutant for which the source is a major source; or
(B) The addition or modification of any stationary source or sources after the initial construction that have cumulative potential emissions greater than or equal to the significant emission rate, excluding any emission decreases.

The PGE Boardman plant has not added any stationary source or sources that have cumulative potential emissions greater than or equal to the SER for any regulated pollutant and has not requested an increase to the Plant Site Emission Limit for any regulated pollutant. Therefore, there has not been a major modification at the facility that would require new source review. [See also the letter sent to PGE in 2002 that discusses Oregon's New Source Review program as it applies to the Boardman plant – Attachment E] **[Note: Based on comments received in 2007, the Department has determined that the source is subject to section (a) of the definition rather than section (c). See appendix F for more explanation.]**

Section 112 State MACT: The comment was made that since EPA decided to regulate hazardous air pollutant emissions from coal fired electric generating units under section 111 instead of section 112 of the Clean Air Act, the Department must establish source specific standards under section 112 of the Act.

Written comments: 21(PEAC IX)

Response:

There are two provisions of section 112 that would require a state to establish a source specific standard for hazardous air pollutants. The first provision is found in section 112(g) and it applies to new sources of hazardous air pollutants. PGE Boardman is not a new source, so this provision does not apply. The second provision is found in section 112(j) and it applies to sources within a source category that is required to have a MACT standard established by EPA, but EPA misses the date by which the standard must be developed. However, since EPA removed coal fired power plants from the list of source categories required to obtain MACT standards, the Department has no authority to establish a standard under section 112(j).

As pointed out in the comments, the decision by EPA to remove coal fired powered plants from the list of source categories subject to section 112 is being challenged in the courts. If the decision is not upheld, EPA will have to establish a new schedule for adopting a standard under section 112. If they were to miss the revised schedule, the Department would be required to establish a standard under section 112(j). However, by that time, the Department will have already adopted a standard as required by the emission guideline provisions of section 111. As mentioned earlier, the Department is on schedule to adopt mercury emission limits for coal fired power plants by the end of this year or early part of next year. **[Note: State mercury standards have been adopted by the EQC and the Boardman Plant has complied with the requirements to date. EPA is required to promulgate federal standards in 2011.]**

Monitoring

The compliance assurance monitoring (CAM) requirement contained in the permit is not adequate because it excludes excess emission events:

Written comments: 21(PEAC VI.A)

Response:

The purpose of the CAM requirement is to monitor the performance of the control device to assure compliance with particulate matter emissions limits. As demonstrated during source tests, the emissions are well below the emissions limits when the control device is operating properly. Visible emissions are used as an indicator of whether the control device is working properly. An action level of 12% opacity was established based on a review of all of the compliance source tests that have been performed over the years. An excursion occurs when the visible emissions exceed 12% opacity during an hour. In addition, a Quality Improvement Plan (QIP) is required if the number of excursions exceeds 5% of the total operating time in a reporting period. Excess emissions are excluded from this analysis.

The comment was made that excluding excess emissions when determining whether a CAM excursion has occurred somehow masks the performance of the control device. The Department does not agree. As discussed in section 6, excess emissions usually occur as a result of the control device being turned off during startup, shutdown, and malfunction events. Therefore, it is pointless to monitor the performance of the device if it is shut down. The excess emissions are not indicative of a poorly operating control device because the control device is simply not operating.

There was also a comment that the Department was incorrect when it stated in the permit review report that continuous particulate monitor systems are not available. The Department agrees that this statement is not correct. It was true at the time of the last permit renewal when CAM was determined for this facility. The language from the previous permit review report was inadvertently carried forward to the current permit review report. However, there is no requirement to revise CAM if new technology becomes available. In addition, continuous particulate matter monitoring devices are still relatively untested and they may have more problems than the good they could do for purposes of CAM.

PM testing frequency: There were comments opposed to the Department's recommendation to reduce the frequency of the particulate emissions testing. In addition, it was commented that the testing is not adequate for determining compliance with all of the standards (0.1 grain/dscf and 0.04 lb/MMBtu).

Written comments: 21(PEAC VI.B, VII.A, VII.B)

Response:

In the permit application, PGE requested that the requirement for conducting annual compliance tests be modified because all of the compliance tests to date have had results well below the standard and in most cases less than half of the standard. The Department agreed because the compliance assurance monitoring requirements have been in place since the last permit renewal. PGE will be required to test annually, unless 2 consecutive tests are less than 50% of the standard, then no further testing is required during the permit term.

Condition 29 of the permit requires that a combined DEQ Method 5 and EPA Method 5 be used to determine particulate emissions. The results of DEQ Method 5 are used to determine compliance with the 0.1 gr/dscf limit because it includes particulate matter captured in both the front and back-half sections of the sampling train. The results of EPA Method 5 are used to determine compliance with the 0.04 lb/MMBtu limit because it only uses the particulate matter captured in the front half of the sample train to calculate the emissions, which is consistent with the basis for the emission limit. When the facility was first permitted, the 0.04 lb/MMBtu limit was established as a more stringent limit than the New Source Performance Standard to ensure that an ESP would be installed to control particulate matter emissions. In essence, the more stringent limit replaced the NSPS limit with the intention that the NSPS reference method would be used to determine compliance and the limit would not apply during startup, shutdown, and malfunctions.

Annual PM emissions monitoring: PEAC commented that the annual emissions monitoring in condition 42 is not clear and does not account for emissions during periods of startup, shutdown, and malfunction.

Written comments: 21(PEAC VI.C)

Response:

Particulate matter, carbon monoxide, volatile organic compound, and lead emissions are determined using emissions factors and production or process throughputs. This is a standard procedure for calculating emissions when not using continuous emission monitoring devices. For example, PGE will monitor the heat input to the boiler and use an emission factor of 0.04 lb/MMBtu to calculate the emissions for each 12-consecutive month period. The calculated emissions will represent emissions during "normal" operations and do not include emissions during startup, shutdown, and malfunction. This is because the Plant Site Emission Limit does not include emissions during startup, shutdown, and malfunction. For one reason, it is difficult to measure. For another reason, the Plant Site Emission Limit is not intended to include excess emissions. OAR 340-222-0041(2) states that the PSEL will be set to the source's potential to emit or netting basis, whichever is less. In division 200, netting basis is defined as the baseline emission rate with adjustments approved in accordance with the rules. The baseline emission rate, as defined in division 200, means the actual emission rate during the baseline period. And, finally, for determining actual emissions during the baseline period, actual emissions equal the average rate at which the source actually emitted the pollutant during a baseline period and that represents normal source operation. Therefore, it is clear from these definitions that the Plant Site Emission Limit is not intended to include emissions during periods of startup, shutdown, or malfunction because they are not representative of normal source operation.

Fly ash disposal monitoring: PEAC commented that the monitoring for the particulate emissions standards that apply to the fly ash handling activities is inadequate.

Written comments: 21(PEAC VI.D)

Response:

Condition 10 of the permit includes work practices for minimizing fugitive emissions from fly ash handling activities. Condition 35 of the permit requires daily monitoring of fugitive emissions. If visible emissions are observed, the permittee must either conduct an EPA Method 9 test or take corrective action to contain the source of emissions. In addition, the permittee must maintain a log of all inspection and maintenance activities listed in Conditions 9, 10, and 11.

In addition to the uncontrolled activities, there are four baghouses on the fly ash silos and unloading area. These are included in the aggregate insignificant activities at the plant because the combined emissions are less than one ton per year. The baghouses are equipped with alarms to notify the operators when the pressure drop increases above a level indicating a potential problem. In addition, there are routine inspection and maintenance activities. Unless there is an extremely good reason for specific monitoring, the Department does not usually require monitoring for insignificant activities. It is time consuming and does not provide an environmental benefit. If the activity is subject to a standard for hazardous air pollutants or there are documented ongoing problems with the activity, the Department would require monitoring specifically for the insignificant activity.

Two people commented that the Department should require PGE conduct ambient monitoring.

Written comments: 13, 19

Response:

Ambient monitoring is required for new or modified sources subject to New Source Review. As discussed above, PGE was not subject to NSR, but they did perform ambient monitoring to validate the air dispersion modeling. The results were well below the ambient air quality standards. There is no authority to require additional monitoring.

Ambient monitoring is planned for the Hermiston area within a year under a separate project. The results of the monitoring will give us a better idea of the air pollution in the area, but it will not provide direct information about the source of the pollution. PGE will be conducting air dispersion modeling for the Regional Haze rules. The results will be available early to mid 2007. **[Modeling has been conducted and the results are available at http://www.deq.state.or.us/aq/haze/pge.htm]**

Compliance:

Excess emissions: Several comments were provided about excess emission events that have occurred at the facility over the years and continue to occur. These can be summarized as follows.

- The NSPS Startup/Shutdown/Malfunction (SSM) exemption must be narrowly applied to Boardman
- The repeated excess emissions are not excusable
- The NSPS SSM exemption must not be applied to conditions that are not based on federal NSPS requirements
- A compliance schedule is required for PGE's ongoing violations

Written comments: 21(PEAC IV.A, VI.B)

Response:

Excess emissions at the Boardman facility are reviewed in accordance with the Department's excess emission rules (OAR 340-214-0300 through 0360), as well as any applicable federal rules, such as the New Source Performance Standards. The purpose of the rules is to:

1) Require that, where applicable, the owner or operator immediately report all excess emissions to the Department;
2) Require the owner or operator to submit information and data regarding conditions that resulted or could result in excess emissions;
3) Identify criteria for the Department to use in determining whether it will take enforcement action against an owner or operator for an excess emissions; and
4) Provide the owner or operators an affirmative defense to enforcement when noncompliance with technology-based emission limits is due to an emergency.

As pointed out in the comments, there are state standards and federal standards that apply to the coal fired electric generating unit. The state standards apply at all times; whereas, the federal standards do not apply during startup, shutdown, or malfunction events. Even so, the federal standards require that the facility be operated at all times in accordance with good air pollution control practices for minimizing emissions. In almost all cases, excess emissions are a result of emissions in excess of the particulate and visible emissions limits. Very rarely, if ever, has there been an excess emission as a result of emissions greater than the sulfur dioxide or nitrogen emission limits.

PGE immediately notifies the Department of excess emissions caused by reasons other than planned startup and shutdown events. The excess emissions are also summarized in the semi-annual monitoring reports.

The majority of the excess emissions occur during startup and shutdown periods for which PGE has approved procedures that they follow. The excess emissions occur during startup and shutdown because the electrostatic precipitator (ESP) that is used to control particulate emissions cannot be operated when the temperature of the exhaust gas is not high enough to prevent moisture condensation that could seriously damage the unit. During a cold startup, it can take 24 to 72 hours to reach the conditions necessary to energize the ESP. This time has been decreased recently due to changes in the startup procedures that PGE follows, but it still takes time to startup a unit of this size. The Department considers excess emissions during startup and shutdown periods unavoidable and enforcement action is not warranted.

Excess emissions due to malfunctions (if they don't lead to a shutdown) or other causes are generally very short in duration and infrequent. These typically last for one or two six-minute averaging periods. There are various reasons for these excess emissions, some truly unavoidable, but others may be due to an action taken to prevent a much more catastrophic event from occurring. The Department evaluates these closely and looks for trends that may suggest an underlying problem, but has not determined that enforcement is warranted at this time.

There were comments suggesting that the number of startup, shutdown, and malfunction events over the past few years has increased and are a result of poor maintenance by PGE. However, the total duration of excess emissions has been less than 5% of the total operating time, which is not unusual for a coal fired power plant. If the startup and shutdown time is not considered, the duration of the excess emissions has been less than 1% of the operating time. It is unavoidable that an emission unit of this design will have excess emissions. The unit must be shut down at least once a year for routine maintenance. In addition, the unit is shut down sometimes due to a drop in demand for electricity. The goal is to minimize the excess emissions as much as possible.

It was also suggested in the comments that PGE be required to submit a compliance plan to eliminate excess emissions. As stated above, this is not feasible. The emissions unit complies with all of the emissions standards, except during periods of startup, shutdown, or malfunction so a compliance plan is not appropriate.

Public participation

The <u>compliance history</u>, including <u>complaints</u> was not fully disclosed in the public notice.

Written comments: 21(PEAC V.B)

<u>Response:</u>

The Department agrees that it was an oversight to not have included information about complaints and enforcement activities in the public notice. Complaints were discussed in the review report, but information about the single enforcement action that occurred during the permit term was not addressed. The Department will make a better effort in the future to include information about complaints and enforcement actions in future public notices. The Department is continually trying to improve the public notice procedures.

As discussed on page 23 of the review report, there were five complaints during the previous permit term. Three of them were attributable to plant startup. The other two were attributable to particulate matter fallout, but it was determined that PGE was not the source of the particulate matter. As for the enforcement action, a Notice of Noncompliance was issued for not immediately reporting an excess emission event. It was a Class II violation. The enforcement action was not referred to the Office of Compliance and Enforcement for formal enforcement action and a civil penalty was not assessed. Under the current regulations, a Warning Letter would be required instead of a Notice of Noncompliance. This was a very minor infraction.

However, since this information was not provided in the public notice, the Department will re-notice the permit and provide the opportunity for submitting additional comments in writing or at a public hearing to be held in the Boardman area.

Information about <u>excess emissions</u> was not included in the public notice.

Written comments: 21(PEAC V.B)

<u>Response:</u>

The Department does not usually include information about excess emissions in the public notices unless they result in enforcement actions. **[Due to the interest for this source, a discussion of the excess emissions has been added to the review report.]**

The files for the PGE Boardman facility should be consolidated in one location.

Written comments: 21(PEAC XII)

<u>Response:</u>

The Department agrees and is taking steps to consolidate the files in the office in Bend.

Comments in support of Title V renewal

Several people provided comments in support of the Title V permit renewal

Written comments: 14, 18
Oral comments: a, f

<u>Response:</u>

We thank those individuals who took the time to comment on this permit.

APPENDIX F: RESPONSE TO PUBLIC COMMENTS (4/11/07 – 6/15/07)

Note: These are the responses to comments received during the pubic comment period ending on 6/15/07. These responses have not previously been shared with the public.

Introduction:

Oregon Title V Operating Permit (Title V Permit) 25-0016 was issued to Portland General Electric (PGE) on July 1, 2001 and was due to expire on July 1, 2006. A timely and complete application for renewal was submitted by PGE on June 22, 2005 so the Title V permit issued on July 1, 2001 remains in effect until the permit is renewed in accordance with OAR 340-218-0120(2)(b).

The Department provided a draft of the renewal permit for public comment on April 27, 2006 and public hearings were held in Boardman on June 15, 2006 and in Portland on June 28, 2006. The comment period ended on July 7, 2006. Over 100 people commented on the permit renewal.

Because of new rules for mercury emission reductions, the Department decided to re-open the comment period and hold additional public hearings. The draft permit was revised to incorporate the mercury rules. The revised draft permit, updated review report, and response to comments were provided for public comment on April 11, 2007. Public hearings were held on May 16, 2007 in Boardman and May 31, 2007 in Portland. The comment period ended on June 15, 2007.

Response to comments:

A summary of the comments is provided on DEQ's website at http://www.deq.state.or.us/er/PGE.htm. Most of the comments were of the same nature as during the first comment period. The Department's response to these comments has not changed. The response to previous comments is provided in appendix E. This document addresses significant new comments received during the most recent comment period ending June 15, 2007.

1. PGE

Comment:

PGE commented that the Department has incorrectly identified the *baseline emission rate*[1] for all pollutants as "zero" because the rules in place for the last 26 years are clear that baseline for a facility permitted for construction, but not yet in normal operating mode in 1978, equals the source's *potential to emit*. PGE believes that the facility was properly permitted in the *baseline period* by virtue of the Site Certificate issued by the Nuclear and Thermal Energy Council (NTEC) on March 24, 1975 and a Temporary Air Contaminant Discharge Permit (ACDP) that issued in April 1977.

Response:

The Department agrees that the rules are clear that the baseline emission rate should equal the potential to emit for a facility that was issued a permit authorizing construction and operation during the baseline period but did not operate during the baseline period. The Department had concluded in previous permit actions that the baseline emission rate for the Boardman facility was zero because the Department did not recognize the Site Certificate as a valid permit substituting for an ACDP and the initial ACDP was assumed to have been issued on December 6, 1979, after the baseline period. However, the Department agrees that the Temporary ACDP issued in April 1977 and was a valid permit authorizing construction and operation of the facility. As such, the facility should have a baseline emission rate equal to the potential to emit.

[1] Terms shown in italics are defined in OAR 340-200-0020.

The rules for Plant Site Emission Limits were adopted by the Environmental Quality Commission (EQC) in 1981 after the PGE Boardman facility had begun operations in 1980. The rules specified that the initial PSEL for existing sources would be set at the *baseline emission rate*, which is equal to the *actual emissions* during the *baseline period* of 1977 or 1978. *Actual emissions* were defined as the average rate at which the source actually emitted the pollutant during the *baseline period* and that represents normal source operation; or, for any source that had not begun normal operation, actual emissions equal the *potential to emit* of the source.

The question of whether the coal fired power plant has a baseline emission rate hinges on whether the source operated in the baseline period or was permitted to construct and operate in the baseline period. The source clearly did not operate during 1977 or 1978 so it remains to be determined whether the source was permitted to construct and operate during the baseline period.

In previous permit actions, and in 2000 when the Department wrote a letter to PGE discussing the applicability of the New Source Review rules as they apply to the Boardman facility, the Department had concluded that the first air quality permit for the facility was issued on December 6, 1979, after the baseline period, so the baseline emission rate was set at "zero" for all pollutants. Upon further review, it was an oversight by the Department to have not recognized the Temporary ACDP that issued by default in April 1977 as a valid permit. Under the current rules, a Temporary ACDP is not defined so the Department would not issue a Temporary ACDP. However, in 1977, DEQ rules concerning ACDPs allowed for the issuance of temporary permits: "If a temporary or conditional permit is issued in accordance with adopted procedures . . ." OAR 340-20-165(10) (DEQ 125, filed 12-16-1976). DEQ general permit issuance rules in effect in 1977 addressed temporary permits in more detail:

> *D. APPLICATION FOR A PERMIT*
>
> * * *
>
> *4) Within 15 days after filing, the Department will preliminarily review the application to determine the adequacy of the information submitted.*
>
> *5) In the event the Department is unable to complete action on an application within 45 days after notification that the application is complete for processing, the applicant shall be deemed to have received a temporary or conditional permit, such permit to expire upon final action by the Department to grant or deny the original application. Such temporary or conditional permit does not authorize any construction, activity, operation or discharge which will violate any of the laws, rules or regulations of the State of Oregon or the Department of Environmental Quality.*
>
> *OAR 340-1-4 at D.4-5 (DEQ 42, filed 4-4-1972).*

This rule appears to have been effective in 1977, as it was apparently not amended until 1988 pursuant to OAR 340-14-020(5) (DEQ 13-1988, filed 6-17-1988).

The temporary ACDP referenced the application, authorized construction and operation of the source, required compliance with all laws, rules or regulations of the state of Oregon or the Department, and included provisions for expiration of the permit upon issuance or denial of a regular permit. These are the same provisions that are included in current permits, albeit current permits have more detail. However, given that the Site Certificate had been issued in 1975 and the temporary ACDP included the general requirement for complying with all laws, rules, and regulations, the emissions limits and standards of the Site Certificate were incorporated into the temporary permit issued by the Department. Eventually, the emissions limits and standards of the Site Certificate were included, without any significant changes, in the final regular ACDP issued on December 6, 1979.

Based on a review of the permitting actions, the Department agrees that construction and operation of the coal fired power plant was permitted in the baseline period and should have a baseline emission rate equal to the potential to emit.

In 2001, the concept of a *netting basis* was added to the PSEL and New Source Review rules to clarify how requests for increases to the PSEL are to be reviewed and approved by the Department. The *netting basis* is defined as the *baseline emission rate* MINUS any emission reductions required by rule, orders, or permit conditions required by the State Implementation Plan (SIP) or used to avoid SIP requirements, MINUS any *unassigned emissions* that are reduced from allowable under OAR 340-222-0045, MINUS any *emission reduction credits* transferred off site, PLUS any emission increases approved through the New Source Review regulations. For sources with *potential to emit* greater than or equal to the *Significant Emission Rate (SER)*, an initial source specific PSEL is set equal to the source's *potential to emit* or *netting basis*, whichever is less. There are no unassigned emissions or emission reduction credits for this facility and there have not been any emission increases approved through the New Source Review regulations. There have been emission reductions required by the federal Acid Rain program for NO_x emissions and more recently for NO_x SO_2, and PM, as a result of the regional haze rules.[2] Therefore, the baseline emission rate and netting basis (all expressed in tons/yr) have been revised as follows:

Pollutant	**Baseline Emission Rate***	**Netting Basis***	
		Previous	**Proposed**
PM/PM_{10}	1056	1056	346
CO	767	767	767
NO_x	17762	12687	1776
SO_2	34050	34050	3405
VOC	92	92	92
Pb	0.17	0.17	0.17

* tons per year

A more complete discussion of the baseline emission rate, netting basis, and Plant Site Emission Limits is provided on page 35 of this review report. The changes to the baseline emission rate and netting basis discussed above do not result in any specific changes to the draft permit. However, the changes could have a bearing on how New Source Review applies in the future. Without a baseline emission rate, the source would be subject to the provisions in section (c) of the definition of *major modification* in OAR 340-200-0020. Under section (c) the source would be subject to the New Source Review regulations if there were an increase in the PSEL by more than 1 ton/yr for any pollutant. In addition, emission reductions from the existing coal fired power plant could not be used to avoid New Source Review if new equipment with emissions greater than the SER of any pollutant were added to the plant. With a baseline emission rate, the provisions of section (a) apply. Under section (a) the source would be subject to the New Source Review regulations only if there are physical changes that would increase the PSEL above the netting basis by more than the SER of any pollutant.

For example, under section (c), the installation of low NO_x burners to reduce NO_x emissions could result in an increase in the PSEL for carbon monoxide (CO) by more than one ton per year, making the source subject to the New Source Review regulations. Under section (a), the PSEL for CO could increase up to 99 tons per year as a result of installing low NO_x burners without the source being subject to the New Source Review regulations.

2. Pacific Environmental Coalition Advocates (PEAC) comments:

a. <u>Comment:</u>

[2] As discussed in the response to previous comments and the draft permit review report, this facility is subject to the Best Available Retrofit Technology (BART) requirements of the Regional Haze program. The EQC adopted BART and regional haze regulations applicable to Boardman. OAR chapter 340, division 223

PGE Boardman should install pollution controls pursuant to New Source Review requirements because:

i. it was improperly grandfathered under the Clean Air Act;
ii. subsequent modifications have triggered NSR under section (c) of the definition of major modification in OAR 340-200-0020; and
iii. DEQ should ensure that the conditions of the Title V permit provide for compliance with all applicable requirements.

Response:

i. grandfathered source:

The Department has responded to the question of whether the source was improperly grandfathered under the Clear Air Act in the previous response to comments. The Department's response to this comment has not changed. According to the EPA, who had authority for the New Source Review regulations at the time, the PGE Boardman coal fired power plant was not subject to the 1974 requirements for Prevention of Significant Deterioration (PSD) because construction had commenced prior to the applicability date of the regulations.

ii. subsequent modifications:

As discussed in the response to PGE's comments above, the Department has determined that the source was properly permitted during the baseline period so section (c) of the definition of major modification no longer applies to the source because the source has a baseline emission rate and netting basis for each pollutant. Instead, the provisions of section (a) of the definition of major modification apply to the facility. Under section (a), a major modification is any physical change that results in an increase in the PSEL above the netting basis by more than the significant emission rate for any pollutant. Until 2009, PGE has not requested any increases in the PSEL as a result of physical changes at the plant. PGE submitted an application on 9/8/09 for increasing the carbon monoxide PSEL as a result of the new low NO_x burners that will be installed to reduce NO_x emissions to comply with the regional haze BART rules.

iii. applicable requirements:

Finally, since the source has not been subject to the NSR regulations, there are no requirements as a result of those regulations to include in the Title V permit. That does not say that the NSR regulations could not apply in the future. If changes are made to the source that are subject to the NSR regulations, the changes would be reviewed in accordance with the NSR procedures and any applicable requirements that come out of that review would be included in the Title V permit.

b. Comment:

DEQ has improperly excused opacity and particulate matter violations and failed to require a necessary compliance schedule.

Response:

This comment was addressed in the previous response to comments, as well as the review report for the revised draft permit. The Department provided a summary of the excess emissions in the recent past and a discussion of whether the excess emissions were considered avoidable or unavoidable. Most of the excess emissions occur during startups and shutdowns when the particulate emission control device cannot be operated because it would be severely damaged. The Department has determined that enforcement actions are not warranted for these unavoidable excess emissions.

c. Comment:

DEQ should regulate carbon dioxide emissions from the Boardman Plant.

Response:

According to EPA, carbon dioxide will become a regulated pollutant in July 2010 when a greenhouse gas emission standard will be finalized for light duty vehicles. EPA has released its reconsideration of the December 18, 2008 Johnson Memo, which addressed when new pollutants, including greenhouse gases (GHGs), are subject to regulation under the Prevention of Significant Deterioration (PSD) program. EPA has now clarified that new pollutants are subject to regulation under PSD when a nationwide rule controlling emissions takes effect. If the GHG light-duty vehicle rule is finalized as proposed, PSD permitting for GHGs would be triggered starting January 2, 2011, which is the earliest date that 2012 vehicles meeting the new emissions standards can be sold in the U.S. This interpretation also applies to Title V permitting, and would not allow pending permit applications to be grandfathered past January 2011. http://www.epa.gov/nsr/guidance.html

3. Ken Thompson (McRae Ranch) Comments

- Carbon based thermo power plants have no quantitative impacts on premature deaths, health, or environmental impacts, but non-road diesel engines do.
- Carbon based thermo power plants do not have to meet as restrictive standards as non-road engines.
- No attempt was made to conduct ambient monitoring with and without the plant operating to determine the impacts from the plant.
- The PGE Boardman coal fired plant should have the same timelines and meet the same emission reduction standards as the latest EPA non-road diesel emission requirements.

Response:

The Boardman facility is subject to a number of regulatory programs. There is a regulatory program for new or modified major stationary sources. This program is referred to as New Source Review (NSR) and includes provisions for the Prevention of Significant Deterioration (PSD) in areas, such as the Boardman area, that the air quality is better than the national ambient air quality standards. The PSD regulations require that a new or modified major source install Best Available Control Technology (BACT) and conduct an air quality analysis to ensure that the emissions will not cause an exceedance of the ambient air quality standards and PSD increments. This analysis takes into consideration not only the individual source's emissions, but also the emissions from other sources in the area. In addition to the NSPS and NSR programs, coal fired power plants are subject to the federal Acid Rain program state mercury requirements..

The NSPS, Acid Rain, and mercury requirements are included in the Title V permit. As discussed above in response to other comments, the coal fired power plant has not been subject to the New Source Review regulations. However, since the source has not been subject to the construction NSR regulations, it is subject to the Best Available Retrofit Technology (BART) requirements of the Regional Haze program. The EQC adopted BART and regional haze regulations applicable to Boardman. OAR chapter 340, division 223.

As pointed out, the coal fired power plant is subject to numerous regulations and the BART rules will require further emission reductions. An estimate of the emission reductions achieved as a result of these regulations is provided in the table below. It is difficult to make a direct comparison between the effects of the regulations on coal fired power plants and non-road engines. Coal fired power plants have tall stacks and the emissions are dispersed over a wide area, diluting the impacts of the emissions. Non-road engine emissions are emitted at ground level and have much more localized impacts.

In addition, the magnitude of emissions from all sources must be considered. While the emissions from an individual non-road engine may be trivial compared to a coal fired power plant, the combined emissions of area and mobile

sources can add up to as much, if not more than point sources. In Oregon, past inventories indicate that point sources (including PGE Boardman) only contribute about 7 to 15% of the total pollution. That is not to say the regulations for point sources are not necessary, but to maintain and improve the overall air quality, it is necessary to regulate area and mobile sources, as well.

The most direct means of measuring the need for and the success of regulations is ambient monitoring. However, ambient monitoring only measures the air quality at a specific location, which may or may not be representative of the entire airshed. In addition, ambient monitoring is very expensive and labor intensive. Therefore, mathematical models are quite often used as a substitute for ambient monitoring. Until recently, the air quality in Boardman and Hermiston area has been estimated for permitting point sources using these models. Just recently, however, an ambient monitoring station was set up in Hermiston using funds from an enforcement action. There is not enough data yet to determine any trends or assess the air quality with and without the PGE Boardman plant operating, but it is a start. The data obtained from the monitoring station can be viewed at the following website: http://www.deq.state.or.us/lab/aqm/rt/rtHourlyConc.aspx

Emission reductions as a result of past and future regulations:

	PM			SO_2			NO_x		
	(lb/MMBtu)	**(tons/yr)**	**(% reduction)**	**(lb/MMBtu)**	**(tons/yr)**	**(% reduction)**	**(lb/MMBtu)**	**(tons/yr)**	**(% reduction)**
Uncontrolled Emissions	3.8[a]	96,425[b]	---	2.8[c]	71,050[b]	---	0.85[d]	21,569[b]	---
NSPS (1979)[e]	0.04[f]	1,015[b]	98.9	1.2	30,450[b]	57.1	0.7	17,762[b]	17.6
Acid Rain (2008)[g]	NA	NA	NA	---	13,373	81.2	0.46	11,672[b]	45.9
Actual (2005)	0.012[h]	696	99.3	---	12,017[i]	83.1	---	8,314[i]	61.5
BART (2014)[j]	0.012	346[b]	99.6	0.12	3,045[b]	95.7	0.23	5,836[b]	72.9
Regional Haze (2017)	---	---	---	---	---	---	0.07	1,776[b]	91.8

a. AP-42 table 1.1-3, dry bottom, walled fired boiler burning bituminous coal with an ash content of 10% and converted to lbs/mmBtu using EPA's conversion factor of 26 MMBtu per ton of coal.
b. Potential to emit based on a boiler design heat input capacity of 5.075 x 10^7 MMBtu/yr (3.8 lb/MMBtu x 5.075 x 10^7 MMBtu/2000 lb/ton)
c. AP-42 table 1.1-3, dry bottom, walled fired boiler burning bituminous coal with a sulfur content of 2.1% and converted to lbs/mmBtu using EPA's conversion factor of 26 MMBtu per ton of coal.
d. AP-42 table 1.1-3, dry bottom, walled fired boiler burning bituminous coal converted to lbs/mmBtu using EPA's conversion factor of 26 MMBtu per ton of coal.
e. 40 CFR Part 60, subpart D
f. Source specific emission limit established by the Department in the initial ACDP.
g. Acid rain permit included in the Title V permit
h. Average of source tests conducted since 1980
i. Continuous monitoring data
j. 40 CFR Part 51, appendix Y
k. Bituminous coal ash and sulfur content from table B-3 of the Boiler Efficiency Manual, KVB, Inc, August 1980

APPENDIX G: RESPONSE TO PUBLIC COMMENTS (4/1/10 – 8/16/10)

Introduction

Portland General Electric (PGE) is required to have an Oregon Title V Operating Permit for the coal fired power plant located near Boardman, Oregon. The Title V permit was first issued on October 22, 1996. Title V permits are required to be renewed every 5 years to ensure that the permits contain the latest requirements and provide an opportunity for public involvement. The Title V permit for the Boardman plant was last renewed on July 1, 2001.

This was the third public comment period for the permit renewal. A draft of the permit was released for public comment on April 27, 2006. Public hearings were held on June 15, 2006 in Boardman, Oregon and on June 28, 2006 in Portland, Oregon. The comment period ended on July 7, 2006. A summary of the comments and the Department's response is provided on DEQ's website at http://www.deq.state.or.us/er/PGE.htm . Shortly after the comment period, the Environmental Quality Commission (EQC) was about to take final action on a rule that would limit mercury emissions from coal fired power plants. Therefore, it was decided to hold off issuing the permit until the mercury rule would be finalized and the requirements could be included in the permit renewal.

A revised draft permit, updated review report, and response to comments were provided for public comment on April 11, 2007. Public hearings were held on May 16, 2007 in Boardman and May 31, 2007 in Portland. The comment period ended on June 15, 2007. A summary of the comments and the Department's responses are provided on DEQ's website at http://www.deq.state.or.us/er/PGE.htm .

Shortly after the end of the second comment period, the federal Clean Air Mercury Rules were vacated and the Department initiated a rulemaking to develop state rules that were independent of the federal rules. In addition, the Department anticipated that regional haze rules that would include Best Available Retrofit Technology requirements for the facility would be adopted in 2008. Issuance of the permit has been postponed to include the mercury and regional haze requirements that will require significant emission reductions. The mercury and regional haze rules were adopted on June 19, 2009. The draft permit has been revised to include the newly adopted requirements.

The comment period for the proposed permit renewal was opened on April 1, 2010 and ended on August 16, 2010. Public hearings were held in Portland on May 4 and in Boardman on May 5. The Department received comments from over 1,500 individuals and organizations during the comment period and at the public hearings. Many of the individuals who provided comments represented the following government agencies and special interest groups:

- Associated Oregon Industries
- Boardman Chamber of Commerce
- City of Boardman
- City of Portland
- Clackamas County
- Columbia Riverkeeper
- David Douglas School Board
- Energy Action Northwest
- Friends of the Columbia Gorge
- International Brotherhood of Electrical Workers
- Laborers Local 121Morrow County
- Northwest Environmental Advocates
- Northwest Environmental Defense Center (NEDC)
- Northwest Pulp and Paper Association
- Pacific Environmental Advocacy Center (PEAC)
- Physicians for Social Responsibility
- Port of Morrow
- Portland Business Alliance
- Portland General Electric (PGE)
- Private Citizens
- Oregon Center for Environmental Health
- Oregon Global Warming Action Network (OGWAN)
- Oregon Physicians for Social Responsibility
- Oregon State Public Interest Research Group (OSPIRG)
- Oregon Toxics Alliance
- Sierra Club
- Tualatin School District
- Venetian Theater and Bistro
- Westside Economic Alliance
- Yakama Nation

The oral and written comments available at http://www.deq.state.or.us/er/PGE.htm. A summary of the comments and DEQ's responses are provided below.

Require immediate controls for SO_2, NO_x, Hg, greenhouse gases (GHG):

Most people requested the DEQ add requirements to the Title V permit for reducing pollutant emissions as soon as possible. They expressed concern that pollutant emissions from the plant cause or contribute to one or more of the following:

- Adverse health effects
- Damage to eco-system (acid rain, elevated pH)
- Contamination of fish and wildlife (mercury deposition)
- Impairment of air quality and visibility in the Columbia River Gorge National Scenic Area
- Impairment of visibility in Class I wilderness areas and national parks
- Global warming
- Damage to Native American rock images
- Consumption of Umatilla and Morrow County airshed

Response:

The Department agrees that these are significant issues. However, Title V is not a program that establishes new requirements for a specific facility. Requirements are established by rule or within pre-construction permits in accordance with the Oregon State Implementation Plan. Title V is a federally-mandated permitting program that consolidates all applicable requirements into one document and provides for adequate monitoring, recordkeeping, and reporting to assure compliance with the requirements. [Federal Clean Air Act 1990 Amendments and 40 CFR Part 70]

The Environmental Quality Commission (EQC) recently adopted rules that establish new requirements for the Boardman Plant. Rules for reducing mercury from coal fired power plants were adopted by the EQC in December of 2006 with revisions in December 2008 and June 2009. Best Available Retrofit Technology (BART) requirements were adopted by the EQC in June 2009. The proposed permit includes the requirements recently adopted by the EQC.

Based on a request by PGE, the BART rules are being reconsidered and may be revised to add one or more options based on early closure of the Boardman Plant. Once the revised rules are adopted, they will be incorporated into the Title V permit.

Plant closure:

On April 2, 2010, PGE petitioned the EQC to revise the BART rules adopted in June 2009. The petition included a proposal to close the plant by December 31, 2020 along with alternative, less stringent BART requirements based on the remaining useful life of the plant (~10 years). The EQC denied the petition, but directed DEQ to proceed with a rulemaking that would provide options for PGE should they decide to close the plant within the next 10 years. The rules have not been finalized, so they cannot be included in the permit at this time.

Quite a few people provided comments regarding closure of the Boardman Plant. The comments ranged from denying the permit and requiring immediate closure to allowing the plant to operate indefinitely in accordance with the current rules.

Response:

Closure of the plant is outside the scope of the title V permit renewal. DEQ does not have the authority to close a source down if the source complies with applicable requirements. It is possible that the BART rules may be revised to add optional requirements for early closure of the plant. Once those rules are adopted, the requirements will be incorporated into the permit.

PEAC Comment I: Permit shield

PEAC requested that the permit include a provision for exempting the NSPS and PSD requirements from the Title V permit shield provisions due to their ongoing litigation efforts.

Response:

The current and proposed permit does not provide a shield for NSPS and PSD modification requirements, and the permit shield of the permit has been revised to clarify this matter. See the permit shield provision of the permit, and also the response to PEAC' Comment IV. Further, because the permit shield cannot apply to violations of applicable requirements prior to or at the time of permit issuance, and because the Boardman plant was constructed before it received its first Title V permit in 1996, the permit shield also does not apply to construction PSD requirements.

PEAC's Comments II and III: Prevention of Significant Deterioration, past and present:

Several people and organizations, including PEAC, commented that the Boardman Plant was subject to the Prevention of Significant Deterioration program when it was constructed in the late 1970's. These people also claim that changes made to the facility since the plant was first constructed were also subject to the PSD program. The PSD program requires best available control equipment and an air quality impact analysis to ensure that the emissions increases as a result of a modification will not exceed national ambient air quality standards and increments that protect against significant deterioration of the ambient air quality.

Response:

Similar comments were provided in the first two public comment periods. Consistent with the responses to comments received during the first two public comment periods, DEQ maintains that the Boardman plant was not subject to the PSD program upon construction. The PSD program was administered by EPA when the plant was first constructed. At that time, EPA determined that the Boardman Plant was not subject to PSD because construction commenced prior to the applicable date of the program. DEQ's PSD program was adopted in 1982. Additionally, DEQ previously responded to public comments by stating that the Boardman facility was not subject to the PSD program as a result of modifications. However, consistent with DEQ's response above to public comments on NSPS applicability, DEQ withdraws its previous response and declines to make a specific finding of non-applicability of any PSD modification requirements. DEQ has reiterated this point in the permit shield provisions of the permit renewal. As explained above, given the complexity of the factual and legal issues involved in resolving whether the Boardman facility undertook a modification or a series of modifications which triggered PSD requirements, and given the existence of a lawsuit that will address that very issue, DEQ declines to make a finding of non-applicability.

PEAC's Comment IV: New Source Performance Standards (NSPS)

Many people and organizations, including PEAC, commented that modifications to the plant between 1998 and 2004 were modifications under the federal New Source Performance Standards (40 CFR 60.14), so the Boardman Plant should have complied with the 1978 standards (40 CFR Part 60, subpart Da) at the time of the modifications. The Title V permit includes a less stringent sulfur dioxide requirement from an earlier NSPS (40 CFR Part 60, subpart D). Modification under the NSPS program means a physical change that increases the

hourly emission rate (lb/hr) of a pollutant regulated by the standard. PEAC filed a lawsuit in 2008 alleging violation of the 1978 NSPS.

Response:

Given the complexity of the factual and legal issues involved in resolving whether the Boardman facility undertook a modification or a series of modifications which triggered NSPS requirements, and given that these issues are being litigated in the case of *Sierra Club, et al. v. PGE*, Federal District Court for the District of Oregon, Case No. CV 08-1136 HA, DEQ declines to make a specific finding of non-applicability of any NSPS modification requirements, and has reiterated this point in the permit shield provisions of the permit renewal.

As PEAC pointed out in its comments, "The applicability of PSD and NSPS to PGE Boardman is currently being litigated in *Sierra Club v. Portland General Electric*. Both of these issues are factually and legally intensive. The best forum for the resolution of these issues is in federal court, where evidence can be presented in an orderly and fair way before an arbiter specially designed to handle the rigors of complex contested matters. The Title V process, with its volley and return of comments, is less suited for disposition of these issues. *Sierra Club v. Portland General Electric*, has been on-going for approximately two years, and is scheduled for trial in June 2011. DEQ has been granted *amicus curia* status and has already filed legal memoranda in the case. Therefore it is appropriate, if DEQ decides to issue the permit before resolution of the litigation, for DEQ to insert a placeholder provision."

In addition to PEAC's lawsuit, the PGE Boardman plant has been issued a Notice of Violation (NOV) by the U.S. EPA for allegedly failing to comply with the 1978 New Source Performance Standards due to modifications in 1998 and 2004. The permit will be reopened to incorporate any applicable requirements resulting from the lawsuit or enforcement action. The permit has been revised to clarify that the permit does not provide a shield against enforcement for the NSPS violations alleged in the Notice of Violation and the lawsuit.

The issuance of an NOV by EPA is not, by itself, sufficient to demonstrate that the permit is not in compliance with the Clean Air Act, pursuant to section 502(b)(2) of the Act. An NOV is an early step in EPA's process for determining whether a violation has occurred. Issuance of an NOV is typically followed by additional investigation, information gathering, and exchanges of views between EPA and the party receiving the NOV. Therefore, an NOV is not a final EPA determination that a violation occurred. Likewise, as a legal matter it is not final agency action subject to judicial review.

In this case, DEQ understands that EPA is still in the process of obtaining further information about whether a violation occurred. For example, EPA plans to meet with PGE in late December to discuss the allegations of the NOV in more detail, at which point DEQ understands that PGE plans to present information rebutting the NOV's allegations that violations have occurred. This meeting will coincide with the timing of PGE's submission of expert witness reports to the court concerning alleged NSPS violations in the *Sierra Club* lawsuit referenced above. Like EPA, DEQ lacks a response from PGE to the allegations that PGE violated NSPS requirements. Therefore, DEQ concludes that it lacks sufficient information at this point to reach a conclusion about whether PGE violated NSPS requirements. Like EPA, will consider additional information from PGE before reaching a conclusion.

Additionally, although the permit does not include the specific requirements of the 1978 NSPS, the permit does include emissions limits that will come into effect on July 1, 2014 that are more stringent than the 1978 NSPS. These limits are based on the BART rules adopted by the EQC in June 2009. The 1978 NSPS regulates sulfur dioxide, nitrogen oxides, and particulate matter. Actual emissions of nitrogen oxides and particulate matter have always been less the 1978 NSPS limits.

In accordance with OAR 340-209-0080(3), PGE was provided the opportunity to submit a written response to any comments submitted by the public within 10 working days after the close of the public comment period. PGE provided information alleging that the modifications in 1998 and 2004 were not a capital expenditure and therefore were not considered a modification under 40 CFR 60.14(e)(2) of the NSPS regulations, but

specifically declined to provide detailed technical information that it will later submit to the court with its expert witness reports in the *Sierra Club* lawsuit.

PEAC's Comment V: Delay Issuance of Permit to include future regulations:

PEAC requested that issuance of the permit be delayed until new regional haze rules, $PM_{2.5}$ regulations, and greenhouse gas regulations are finalized. In addition, PEAC commented that the permit should include a Plant Site Emission Limit in accordance with temporary rules adopted in August 2010.

Response:

DEQ processes permits in accordance with the regulations in effect at the time. Waiting to issue a permit pending the development of future regulations would result in an unworkable program because new regulations are constantly being adopted or revised. DEQ previously delayed issuance of this permit because the existing permit remained in effect and included all current requirements. However, it is imperative now that the permit be issued because new regulations have been adopt that require compliance in 2011.

Because of the nature of the temporary rule and the fact the public notice for the permit renewal began well before the temporary rule was adopted, DEQ is not including a Plant Site Emission Limit for $PM_{2.5}$. The temporary rule was intended to provide DEQ the authority to implement PSD regulations (Division 224) for $PM_{2.5}$ when EPA repeals the 1997 PM_{10} surrogate policy. The surrogate policy has not been repealed yet. Although a Plant Site Emission Limit is not included in the permit, a requirement for PGE to submit a request for a permit modification to include the Plant Site Emission Limit has been added to the permit. The application for the modification is due within 30 days after the final $PM_{2.5}$ rules are adopted (current schedule is February 2011) or sooner if there is a modification that will increase $PM_{2.5}$ emissions and it occurs after the surrogate policy is repealed. The temporary rules limit $PM_{2.5}$ to the filterable portion of the total $PM_{2.5}$ emissions. Therefore, if a PSEL were established at this time, it would have to be revised once the final $PM_{2.5}$ rules are adopted.

EQC rules have not yet been adopted to limit emissions of greenhouse gases (GHG). However, GHG will become a regulated pollutant on January 2, 2011 in accordance with EPA's tailoring rule. The Boardman Plant is an existing major source of GHG. The tailoring rule would apply to the Boardman Plant if there is a modification after January 2, 2011 that will increase GHG by 75,000 tons or more.

PEAC Comment VI: Frequency of Performance Tests:

PEAC commented that the frequency of the particulate matter performance test should not be reduced from annual to once during the five year permit term because the boiler is getting older. Emissions may change over time and performance tests are the only way DEQ can assure that the emissions unit is meeting the emissions limits. PEAC also pointed out several inconsistencies between the permit and various sections of the review report with regards to the test frequency.

Response:

DEQ has reduced the testing frequency consistent with test requirements in other Title V permits when test results are consistently well below the emission limit. Although there may be fewer tests in the future, PGE is required to continue to monitor visible emissions and take corrective action if there is an excursion of a 10% action level in accordance with the Compliance Assurance Monitoring provisions in the permit. There is no direct correlation between visible emissions (e.g., opacity) and particulate matter, but opacity is a good indicator of the ESP performance. If the ESP is working properly, opacity should be less than 10% and past performance tests have shown that the PM emissions will be well below the emission limit. DEQ has addressed the inconsistencies in the review report.

PEAC Comment VII: Startup/shutdown/malfunction emissions

PEAC raised the concern that DEQ is not ensuring that the NAAQS or PSD increments are protected because emissions during startup/shutdown/malfunction are not included in the PSELs and annual emission calculations.

Response:

The Plant Site Emission Limits for the Boardman Plant are based on the source's potential to emit when it runs at maximum capacity. The maximum capacity of a source does not necessarily equate to the maximum pollution a source can generate. The concept of PTE refers to a source operating within its own design constraints – as it is intended to be operated and as it is normally operated. When possible, DEQ includes startup/shutdown emissions if these are routine events and there is a way to quantify the emissions during these periods of operation. However, for the Boardman Plant, the PM, VOC, and CO emissions during startup/shutdowns are neither predictable nor routine and any estimate of the emissions would only inflate the PSEL without a method for determining compliance at this time.

The PSEL is based on the PTE of the Boardman Plant in accordance with the definition of actual emissions in OAR 340-200-0020 because the Boardman Plant was permitted to construct and operated during the 1977/1978 baseline period but had not begun normal operations. As with any other source permitted to operate in the baseline period, the PSEL was established without requiring an analysis of the air quality impacts. Significant increases in the PSEL whether or not it is due to a major modification require an air quality analysis to ensure the increase will not exceed PSD increments or NAAQS.

PEAC Comment VIII: Opacity and particulate matter violations

PEAC raised the concern that DEQ has improperly excused opacity and particulate matter violations and fails to present PGE Boardman's excess opacity and particulate matter emissions in a consistent and comprehensible way.

Response:

DEQ does not agree with PEAC. The response to previous comments and the review report for the current draft provide a detailed analysis of the excess emissions. Most of the excess emissions occur during startup and shutdown due to the design of the facility as it was permitted in 1977 in accordance with the regulations in place at the time. NSPS takes into consideration the design limitations by providing an exemption from the opacity and particulate matter limits during periods of startup/shutdown/malfunction events. For purposes of the NSPS, exceedances during startup/shutdown/malfunctions are not considered violations. The state general opacity and particulate matter standards apply at all times. DEQ has exercised enforcement discretion for excess emissions during startup/shutdown because they are considered unavoidable excess emissions. The Boardman plant must shutdown periodically for maintenance. In addition, there are occasional forced outages for safety reasons. When the plant resumes operations, the ESP that collects particulate matter cannot be energized right away or it would be seriously damaged.

PEAC Comment IX: Unauthorized fuel

PEAC raised the concern that unauthorized bituminous coal has been burned at the Boardman Plant, which is a violation of permit condition 19.a.

Response:

Permit condition 19.a limited the type of coal to sub-bituminous western coal. However, there is no underlying authority for this requirement, other than the initial Air Contaminate Discharge Permit (ACDP) issued in 1979. The ACDP limited coal to "western coal" without specifying the specific type of coal (e.g., sub-bituminous or bituminous). The original Title V permit issued in 1996 inadvertently limited the type of coal to sub-bituminous

coal because that is what is or was typically burned at the Boardman Plant. Upon further review, DEQ is changing the condition to reference "western coal" rather than specifying specific types as originally permitted. This change has no effect on the emissions from the plant or compliance with the emission standards. Continuous monitoring systems are used to determine compliance with the sulfur dioxide and nitrogen oxide emissions. Compliance with the particulate matter limit is determined by source testing. The plant site emission limits are either based on regulatory limits (PM, SO_2, and NO_x) or AP-42 emission factors (CO and VOC). The CEMS mentioned previously are used to determine compliance with the PSEL for SO_2 and NO_x. An emission factor based on annual source tests is used to determine compliance with the PSEL for PM. AP-42 emission factors are used to determine compliance with the PSEL for CO and VOC. The AP-42 emission factors for CO and VOC are the same for bituminous and sub-bituminous coals.

PEAC Comment X: Summary of Comments:

PEAC basically summarizes the previous 9 comments, but also request an explanation for how and where hydrogen is used at the Boardman Plant.

Response:

PGE uses hydrogen at the Boardman Plant for cooling purposes. The permit review will be revised to provide clarification.

PGE Comment: BART Requirements

PGE requested that the 2009 BART requirements be incorporated by reference pending potential revision to the requirements.

Response:

The request has been denied because it is common practice for DEQ to include the specifics of a requirement in the permit for clarity. In addition, it is not a foregone conclusion that the revisions to the BART rules would eliminate the current requirements. The rules may be revised to add options, but the current rules may remain as one option.

PGE Comment: BART Compliance Monitoring

PGE commented that the Part 75 requirements and EPA test methods requirements use for demonstrating compliance with the BART limits should be those in effect on the date the permit is issued rather than June 19, 2009.

Response:

The effective date of the Part 75 requirements and EPA test method requirements is provided in the regional haze rules, so the date can't be change unless the rules are changed.

PGE Comment: Mercury Requirements

Condition 31 identifies a requirement that was satisfied over one year ago. This was a one-time obligation, so it should be removed from the permit.

Response:

DEQ agrees. The requirement has been removed from the permit.

PGE Comment: Plant Site Emissions Limits (PSELs)

PGE requested that future reductions to the PSEL due to the BART requirements be incorporated by future permit modifications rather than including them at this time.

Response:

DEQ has included the reductions because the reductions will occur before the permit expires and including the reductions could avoid unnecessary permit modifications.

PGE Comment: Mercury Monitoring

Section 23 of the Review Report indicates that the mercury certification test is still under review. PGE requests that this be updated to reflect that the mercury CEM is certified.

Response:

DEQ agrees and has made the requested change.

PGE Comment: Netting Basis

PGE believes the DEQ does not have the authority to reduce the netting basis prior to compliance date of a rule as indicated in section 35.c of the review report.

Response:

DEQ does not agree. The definition of netting basis in OAR 340-200-0020 requires a reduction to the netting basis based on reductions required by rule. Based on the plain language of the definition, the netting basis should be reduced at the time that reductions are required by rule. Also, since the reduction to the netting basis is intended to prevent a source from utilizing emission reductions required by rule for netting purposes, DEQ has determined the reduction should occur on the date the rule is adopted and not a future compliance date, which would allow the source to use the reduction for netting.

PGE Comment: NESHAP Applicability

PGE requested clarification to the response to comments in 2007. Mercury standards have been adopted by the EQC and the Boardman Plant has complied with the requirements to date. In addition, PGE provides a analysis of why the Boardman Plant is not subject to the section 112(j) case-by-case MACT standards if EPA misses a deadline for establishing the requirements.

Response:

DEQ acknowledges the comments made by PGE. Clarification has been provided in Appendix E of the review report that state mercury standards have been adopted and the Boardman Plant has complied with the requirements to date.

PGE E-mail Comment (5/17/10):

PGE commented that the Boardman Plant is subject to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for gasoline dispensing facilities (GDF).

Response:

The permit has been revised to include the GDF requirements.

Support for issuing the Title V permit

Several individuals provided comments in support of issuing the Title V permit. The Boardman Plant provides reliable electricity, jobs, and economic vitality to Morrow and Umatilla Counties.

Response:

Thank you for the comments.

PGE's Response to Comments submitted on August 31, 2010:

Pursuant to OAR 340-209-0080(3), the permit applicant may submit a written response to any comments submitted by the public within 10 working days after the close of the public comment period. PGE provided responses to PEAC's comments on August 31, 2010. A summary of the comments is provided below. DEQ read and considered the comments, but is not providing a specific response to the comments.

- PEAC's historical background section is inaccurate and misleading.
- DEQ has neither the authority nor the need to insert a "placeholder" provision in the Boardman Title V permit.
- The Boardman Plant was not subject to PSD when it was initially constructed.
- PSD has never subsequently been triggered at the Boardman Plant as there has never been a major modification.
- Contrary to PEAC's erroneous assertions, Boardman is not subject to the 1978 NSPS because there is clearly regulatory exception.
- DEQ should not delay in issuing the Boardman Title V permit.
- DEQ has appropriately exercised its authority in reducing the source testing requirements for particulate.
- The Department should reject PEAC's request to add startup/shutdown/and upset emissions to the PSEL compliance monitoring.
- PEAC's comment regarding DEQ's past exercise of enforcement discretion is not relevant to the issuance of the Title V permit.
- The Title V permit should allow for the combustion of bituminous coal.
- Clarify the use of hydrogen in the review report.