

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

Eastern Region
300 SE Reed Market Road
Bend, OR 97702

Source Information:

SIC	4911
NAICS	221112

Source Categories (Part and code)	
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Compliance and Emissions Monitoring Requirements:

Unassigned emissions	
Emission credits	
Compliance schedule	
Source test [date(s)]	Annual RATA

COMS	
CEMS	X
Ambient monitoring	

Reporting Requirements

Annual report (due date)	2/15
Emission fee report (due date)	2/15
SACC (due date)	2/15 and 7/30
Quarterly report (due dates)	1/30, 4/30, 7/30, 10/30

Monthly report (due dates)	
Excess emissions report (due date)	15 days after event
Other reports	

Air Programs

NSPS (list subparts)	A, D, Db, GG
NESHAP (list subparts)	
CAM	
Regional Haze (RH)	
Synthetic Minor (SM)	
Part 68 Risk Management	X
CFC	
RACT	
TACT	

Title V	X
ACDP (SIP)	
Major HAP source	
Federal major source	X
NSR	
PSD	X
Acid Rain	X
Clean Air Mercury Rule (CAMR)	

TABLE OF CONTENTS

LIST OF ABBREVIATIONS USED IN THIS REVIEW REPORT	3
INTRODUCTION.....	4
PERMITTEE IDENTIFICATION	5
FACILITY DESCRIPTION	5
EMISSIONS UNIT AND POLLUTION CONTROL DEVICE IDENTIFICATION.....	6
EMISSION LIMITS AND STANDARDS, TESTING, MONITORING, AND RECORDKEEPING.....	8
PLANT SITE EMISSION LIMITS.....	14
GENERAL BACKGROUND INFORMATION.....	15
COMPLIANCE HISTORY	15
SOURCE TEST RESULTS	15
PUBLIC NOTICE.....	17
ATTACHMENT 1: EMISSIONS DETAIL SHEET	18
ATTACHMENT 2: EXPLANATION OF PSEL TERMS.....	21

LIST OF ABBREVIATIONS USED IN THIS REVIEW REPORT

AMB	Ambient	Mlb	1000 pounds
AQMA	Air quality management area	MON	Monitoring
ASTM	American Society of Testing and Materials	NA	Not applicable
BDT	Bone dry ton	NESHAP	National emission standard for hazardous air pollutants
CEMS	Continuous emissions monitoring system	NO _x	Oxides of nitrogen
CFR	Code of Federal Regulations	NSPS	New source performance standard
CMS	Continuous monitoring system	NSR	New source review
CO	Carbon monoxide	O ₂	Oxygen
COMPL	Compliance	OAR	Oregon Administrative Rules
COMS	Continuous opacity monitoring system	ORS	Oregon Revised Statutes
COND	Condition	O&M	Operation and maintenance
CRED	Credit	Pb	Lead
DEQ	Oregon Department of Environmental Quality	PCD	Pollution Control Device
dscf	dry standard cubic feet	PM	Particulate matter
EF	Emission factor	PM ₁₀	Particulate matter less than 10 microns in size
EPA	United State Environmental Protection Agency	PSD	Prevention of significant deterioration
EU	Emissions unit	PSEL	Plant Site Emission Limit
FCAA	Federal Clean Air Act	SCHED	Schedule
gr/dscf	grains per dry standard cubic feet	SPEC	Special
HAP	Hazardous air pollutant	SO ₂	Sulfur dioxide
ID	Identification code	ST	Source test
I&M	Inspection and maintenance	VE	Visible emissions
MB	Material balance	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 on May 14, 2003 and scheduled to expire on May 1, 2008. A complete renewal application was submitted on March 22, 2007 so the current permit will remain in effect until the proposed renewal is issued. Changes to the permit are summarized in item 3 below.
2. In accordance with OAR 340-218-0120(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. In addition, 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. Provided below is a condition by condition discussion of the changes being made to the permit.

New Condition Number	Old Condition Number	Change	Reason
Cover page	Cover page	Designated representative, facility contact	Changes in personnel
1	1	No changes	
2	2	Explained meaning of 'federally enforceable' and amended state only enforceable conditions	EPA review and changes to general conditions
---	3.a and 3.b	Deleted	Combustion turbine 2 has been installed
4 - 21	4 - 21	No changes	
22	22	Changed cross reference to monitoring condition	See condition 41
23	---	Added emission fee information	This change is provided to clarify what the permitted emissions are for each process/pollutant if the permittee pays on actual emissions for one or more process/pollutants.
24 - 25	23 - 24	No changes	
---	25	Deleted	The initial performance test for combustion turbine 2 has been conducted.
26 - 38	26 - 38	No changes	
39	39	Added provisions for sulfur monitoring	This change is based on revisions to subpart GG (40 CFR 60.334(h)(3))
40	40	No changes	
41	41 - 43	Combined conditions and reformatted	This change incorporates the "emission basis" from DEQ's database to facilitate emissions inventory, as well as demonstrating compliance with the PSELs.
42 - 46	44 - 47	No changes	
47	49	Revised excess emissions reporting requirements to include an "immediate" notification as well as a written report within 15 days.	These changes are based on EPA's review of DEQ's program and revisions to the excess emission rules in Division 214.

New Condition Number	Old Condition Number	Change	Reason
48	50	Changed the permit deviation reporting requirement from 7 days to 15 days.	This change is based on EPA's review of DEQ's program and revision to the definition of "prompt" in OAR 340-218-0050(3)(c).
---	51	Deleted	This is redundant with condition 24, which references the source sampling manual.
49 – 50	52 – 53	No changes	
51	54	No changes, except 51.b.iii now only requires a summary of the upset log	A written report is now required within 15 days of each excess emission event so only a summary of the log is required to be reported semi-annually.
52	55	b. and c. of this condition have been revised to clarify compliance status reporting .	This change is based on EPA's review of DEQ's program and revisions to OAR 340-218-0080(6)(c).
53	56	No changes	
54	57	The scope of the non-applicable requirements has been narrowed to just address those requirements that could conceivably be considered applicable.	This is based on EPA's review of DEQ's program.
G1 – G29	G1 – G28	Added condition G3 and revised condition G13 (old G12).	These changes are based on EPA's review of DEQ's program as well as changes to the emission fee rules.

PERMITTEE IDENTIFICATION

- Portland General Electric (PGE) Company operates an electric power generation facility located in Boardman, Oregon. The facility is a Phase II acid rain source. The facility is commonly referred to as the Coyote Springs Plant. Elevation of the site is approximately 285 feet above sea level.

FACILITY DESCRIPTION

- The Coyote Springs Plant is an electric power generation facility using two General Electric combustion turbines. Each combustion turbine includes a duct burner, heat recovery steam generator (HRSG) and steam turbine. The facility also includes one auxiliary boiler. The combustion turbines and auxiliary boiler have individual stacks. Also located on site is a natural gas fired pipeline heater and emergency fire pump, which uses distillate oil. The primary fuel for the combustion turbines and auxiliary boiler is natural gas. Combustion turbine 1 can also burn distillate fuel oil as a back up to the natural gas.
- The basic operating scenario for the Coyote Springs Plant is to run the combustion turbines on natural gas (primary fuel) during the majority of the year, and combustion turbine 1 on distillate oil (backup fuel) during periods of natural gas curtailment. The auxiliary boiler operates only on natural gas fuel and is used for plant startups, plant testing, and to provide steam to the industry hosts when the turbines are not operating. The boiler is currently being operated at less than 10% of the annual capacity.

EMISSIONS UNIT AND POLLUTION CONTROL DEVICE IDENTIFICATION

7. Summary of ID Numbers for the Coyote Springs Plant Title V Application

<u>ID#</u>	<u>Description</u>
OS1	Plant operating scenario.
	<u>Device\Process IDs:</u>
CT1.DV	Combustion Turbine 1
CT2.DV	Combustion Turbine 2
AB.DV	Auxiliary boiler
	<u>Control Device IDs:</u>
SCR.CD1	Selective catalytic reduction (SCR) control for combustion turbine NO _x emissions from combustion turbine 1;
SCR.CD2	SCR control for combustion turbine NO _x emissions from combustion turbine 2.
	<u>Emission Unit IDs:</u>
CT1.EU	Combustion Turbine 1, emissions unit
CT2.EU	Combustion Turbine 2, emissions unit
AB.EU	Auxiliary Boiler Package (3 boilers), emissions unit
PH.AIEU	Natural Gas Pipeline Heater, aggregate insignificant emission unit (1 source)
	<u>Compliance Demonstration Point IDs:</u>
CT1S.CDP	Combustion Turbine 1 stack
CT2S.CDP	Combustion Turbine 2 stack
ABS.CDP	Auxiliary Boiler Package stack
	<u>Other IDs used at the plant</u>
CTG	Combustion Turbine Generator
HRSG	Heat Recovery Steam Generator
PNG	Pipeline Natural Gas
STG	Steam Turbine Generator

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

- 8.a. Combustion Turbine 1 (CT1.EU): This combustion turbine is a General Electric Model Frame7FA with a rated capacity of 1,925.2 million Btu/hr heat input. The turbine is designed to burn natural gas at a rate of 1.797 million cubic feet per hour or No. 2 distillate fuel oil at a rate of 13,799 gallons per hour. A Selective Catalytic Reduction (SCR) device is used to control nitrogen oxides emissions. The combustion turbine is for electric power generation. In addition, the exhaust gases are used in a heat recovery steam generator (HRSG) to generate steam to power a steam turbine generator. There is also a small natural gas fired duct burner that is used to increase the temperature of the exhaust gases from the combustion turbine before entering the HRSG. The rated capacity of the duct burner is 50 million Btu/hr heat input at a fuel rate of 4,915 cubic feet of natural gas per hour.
- 8.b. Combustion Turbine 2 (CT2.EU): This combustion turbine is a newer generation General Electric Model Frame7FA with a rated capacity of 1,987.1 million Btu/hr heat input. The turbine is designed to burn only natural gas at a rate of 1.855 million cubic feet per hour. A Selective Catalytic Reduction (SCR) device is used to control nitrogen oxides emissions. The combustion

turbine is used for electric power generation. In addition, the exhaust gases are used in an HRSG to generate steam to power a steam turbine generator. There is also a duct burner before the HRSG with a rated capacity of 201.8 million Btu/hr heat input at a fuel rate of 197,639 cubic feet per hour.

- 8.c. Auxiliary Boiler (AB.EU): The auxiliary boiler is a water tube boiler used to generate steam to warm up the plant's steam turbine system during cold startup, or to provide steam to an industry host during plant shutdown. The boiler was made by Foster-Wheeler with a rated heat input of 720 million Btu per hour at a design steam pressure of 375 psig and temperature of 442°F. Natural gas is the only fuel used in the boiler at a maximum rate of 0.69 million cubic feet per hour. There are no add-on emissions control devices.
- 8.d. 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.e. Aggregate Insignificant Activities (AI): The aggregate insignificant emissions activities at the facility include a small natural gas pipeline heater and an emergency fire pump.
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 OAR chapter 340, 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
 - Distillate oil, kerosene, and gasoline 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
 - 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
 - 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
- Pressurized tanks containing gaseous compounds
- Emission from wastewater discharges to publicly owned treatment works (POTW) provided the source is authorized to discharge to the POTW, not including on-site wastewater treatment and/or holding facilities
- Storm water settling basins
- Paved roads and paved parking lots within an urban growth boundary
- Hazardous air pollutant emissions of fugitive dust from paved and unpaved roads except for those sources that have processes or activities that contribute to the deposition and entrainment of hazardous air pollutants from surface soils
- 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
- Oil/water separators in effluent treatment systems
- Combustion source flame safety purging on startup

EMISSION LIMITS AND STANDARDS, TESTING, MONITORING, AND RECORDKEEPING

Provided below is a discussion of the emission limits and standards that apply to this facility, including any changes from the previous permit.

Oregon Administrative Rules

10. Fugitive emissions (OAR 340-208-0210(2)) - Permit Condition 4: This requirement is basically a good housekeeping requirement to prevent fugitive emissions from leaving the plant site. Although this requirement is applicable, the facility is not really a source of fugitive emissions so there is no specific testing or monitoring required for this requirement. Any problems would be detected as a complaint as monitored by Permit Condition 30.
11. Nuisance - Permit Conditions 5 and 6: These requirements prohibit nuisances (OAR 340-208-0300) and particulate fallout (OAR 340-208-0450). These requirements, which became applicable to all sources in Oregon on July 1, 2001, replace the odor nuisance condition in the previous permit. These requirements are not part of the State Implementation Plan (SIP) so they are only enforceable by the State. Nuisance conditions must be verified by the Department. In order to determine whether a nuisance condition may exist, the permittee is required to keep a log of any complaints and report them to the Department (Permit Condition 30). The permittee is also required to respond to the complainant within a reasonable amount of time and conduct an investigation as to whether any operations under their control may have caused a nuisance condition.
12. Fuel sulfur content (OAR 340-228-0110(1)) – Permit Condition 12: Natural gas is the primary fuel used at the facility, but distillate oil may be used in combustion turbine 1 when natural gas is not available. If distillate oil is used, this requirement limits the amount of sulfur in the fuel to 0.5% by weight. This requirement also applies to fuel suppliers, so it is unlikely that the permittee could obtain any fuel with higher sulfur levels. To assure compliance with this requirement, the permittee is required to obtain a certificate from the fuel vendor or have samples of the fuel analyzed for sulfur (Permit Condition 34).
13. Visible emissions limit (OAR 340-208-0110(2)) – Permit Condition 10: This requirement limits visible emissions from any emissions point at the facility, including fugitive emissions, to less than 20% opacity, except for an aggregate period of 3 minutes in any 60 minute period. "Opacity" means the degree to which an emission reduces transmission of light and obscures the view of an object in the background. Most of the activities at the facility are insignificant sources of fine particulate matter, which is what usually causes

visible emissions. Insignificant emissions units are discussed below. The standard also applies to the combustion turbines and auxiliary boiler. However, it is very unlikely that the standards would be exceeded when burning natural gas so there is no monitoring required when burning natural gas other than tracking the type of fuel being burned. If oil is burned in combustion turbine 1, the permittee is required to perform a visible emissions survey once a day and conduct a visible emissions test if visible emissions are present for more than 5% of the survey period (Permit Condition 32). Any violations must be documented and reported to the Department.

14. Particulate matter grain loading limit for equipment other than boilers (OAR 340-226-0210(2)) – Permit Condition 11: This requirement limits particulate matter emissions to 0.1 grains¹ per dry standard cubic foot of exhaust gas. Most of the activities at the facility are insignificant sources of particulate matter. Insignificant emissions units are discussed below. The standard also applies to the combustion turbines. However, it is very unlikely that the standard would be exceeded when burning natural gas so there is no monitoring required when burning natural gas other than tracking the type of fuel being burned. If oil is burned in combustion turbine 1, the permittee is required to perform the visible emissions monitoring described above and conduct a particulate emissions source test if oil is burned more than 438 hours per year (Permit Condition 25).
15. Particulate matter grain loading limit for boilers (OAR 340-226-0210(2)) – Permit Condition 18: This requirement limits particulate matter emissions from the auxiliary boiler to 0.1 grains per dry standard cubic foot of exhaust gas at 50% excess air. Since the boiler only burns natural gas, it is very unlikely that the standard would be exceeded so there is no monitoring required other than tracking the type of fuel being burned (Permit Condition 31).

Prevention of Significant Deterioration (PSD)

This facility was originally permitted under the Prevention of Significant Deterioration (PSD) rules. The specific emission limits and standards established for the facility are discussed below:

16. Operating modes (1995 ACDP, Condition 16)– Permit Condition 9: To ensure that the emissions from the combustion turbines and auxiliary boiler would stay within the parameters used in the air dispersion modeling, specific operating modes were established. Natural gas is the only fuel allowed to be burned in combustion turbine 2 and the auxiliary boiler. Distillate fuel oil may be burned in combustion turbine 1 as a backup to the primary fuel (natural gas). These operating modes are monitored by tracking the type of fuel being burned in the combustion devices (Permit Condition 31).
17. Particulate Matter mass emissions limits (1995 ACDP, Condition 3) – Permit Condition 11: Particulate matter emissions from the combustion turbines are limited to 4.5 lbs/hr when burning natural gas and 33 lbs/hr when burning oil (combustion turbine 1 only). The monitoring described in item 13 above is used to assure compliance with these limits.
18. Nitrogen oxide emissions limits (1995 ACDP, Condition 4) – Permit Condition 13: Nitrogen oxide emissions from the combustion turbines are limited to 4.5 ppm @15%O₂ and 30 lbs/hr as a 24-hour rolling average while burning natural gas; and, 15 ppm @ 15%O₂ and 113 lbs/hr as a 24-hour rolling average while burning oil (combustion turbine 1 only). These limits do not apply during periods of startup and shutdown. A continuous emissions monitoring system (CEMS) is required on each combustion turbine stack for monitoring compliance with the emission limits (Permit Condition 36).
19. Carbon monoxide emissions limits (1995 ACDP, Condition 5) – Permit Condition 15: Carbon monoxide emissions from the combustion turbines are limited to 15 ppm @15%O₂ and 51 lbs/hr as an 8-hour rolling average while burning natural gas; and, 20 ppm @ 15%O₂ and 69 lbs/hr as an 8-hour rolling average while burning oil (combustion turbine 1 only). These limits do not apply during periods of startup and shutdown. A continuous emissions monitoring system (CEMS) is required on each combustion turbine stack for monitoring compliance with the emission limits (Permit Condition 38).

¹ A grain is a unit of weight. There are 7000 grains in a pound.

Federal Requirements

20. New Source Performance Standards (40 CFR Part 60): The following New Source Performance Standards (NSPS) apply to the emission units at the facility:

20.a. The combined cycle combustion turbines are subject to Subpart GG. The NO_x limit was determined as follows:

$$\text{STD} = 0.0075 (14.4/Y) + F$$

Where,

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis) [Note: To convert from % to ppm multiply by 10,000 (1,000,000/100)]
 Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour. [Note: The value of Y for each turbine is approximately 10.8 kilojoules per watt hour.]
 F = NO_x emission allowance for fuel-bound nitrogen, as defined in 60.332(a)(3). [Note: F = 0 for pipeline quality natural gas]

- 20.b. The duct burner on combustion turbine 1 is not subject to any NSPS because it has a rated capacity of less than 100 million Btu/hr heat input.
- 20.c. The duct burner on combustion turbine 2 is subject to Subpart Db because the rated capacity is greater than 100 million Btu/hr heat input. However, because only natural gas is burned in the duct burner, the only standard that applies is the NO_x limit in 60.44b(a)(4).
- 20.d. The Heat Recovery Steam Generators (HRSG) downstream of each combustion turbine are not subject to any NSPS because they do not have internal burners.
- 20.e. A CEMS is used to determine compliance with all of the NO_x limits for each combustion turbine. The NSPS requires an initial performance test using Method 20, but no routine stack emissions monitoring. There is a requirement to monitor the fuel nitrogen content, but PGE obtained approval to use the CEMS to determine compliance with the emissions limit rather than monitor the fuel nitrogen. For combustion turbine 2, it is not possible to measure the combustion turbine emissions separately from the duct burner emissions. Therefore, the emissions are measured at the stack using the CEMS and the permittee must comply with all of the applicable emission limits.
- 20.f. The auxiliary boiler is a steam generator but not an electric steam generator. The rated capacity is greater than 250 million Btu/hr heat input so it is subject to Subpart D and Db. Since the auxiliary boiler only burns natural gas, it is not subject to the SO₂ standards in subpart D and it is not subject to the PM, Opacity, and SO₂ standards in Subpart Db. It is subject to the PM, Opacity, and NO_x standards in Subpart D and the NO_x standard in Subpart Db.

Summary of New Source Performance Standards:

Emissions Unit	40 CFR Part 60 Subpart	Citation	Pollutant	Limit	Comments
CT1 and CT2	GG	60.332(a)(1)	NO _x	100 ppm @ 15%O ₂	This is included in Permit Condition 14. The NSPS limit is considerably less stringent than the BACT limit of 4.5 ppm.
		60.333(a)	Fuel sulfur content	0.8% by weight	This is included in Permit Condition 16. The NSPS limit is considerably less stringent than the state limit for distillate fuel oil (0.5% by weight). In addition, pipeline quality natural gas has virtually no sulfur.
CT2	Db	60.44b(a)(4)	NO _x	0.20 lb/million Btu heat input	This is included in Permit Condition 14. This limit applies to the duct burner on CT2 because it has a rated capacity greater than 100 million Btu/hr heat input. It does not apply to the duct burner on CT1 because the rated capacity is less than 100 million Btu/hr heat input
AB	D	60.42(a)(1)	PM	0.10 lb/million Btu heat input	This is included in Permit Condition 19. Since only natural gas is burned in the boiler, it is unlikely that this standard could be exceeded.
		60.42(a)(2)	Visible Emissions	20% opacity, 6 minute avg., except one 6-minute period in an hour may be as high as 27% opacity	This is included in Permit Condition 17. Since only natural gas is burned in the boiler, it is unlikely that this standard could be exceeded.
		60.44(a)(1) and 60.44b(a)(1)	NO _x	0.20 lb/million Btu heat input	This is included in Permit Condition 20. Subpart D requires a CEMS unless the emissions are less than 70% of the standard (e.g., 0.14 lb/million Btu). Subpart Db requires a CEMS unless the annual capacity factor is less than 10%. The emissions measured during the initial performance test were less than 70% of the standard and the annual capacity factor has remained below 10%. Therefore, a CEMS is not required.

20.g. NSPS general provisions: Provided below is a discussion of the NSPS general provisions.

Section	Requirement	Permit action
60.7(a)(1)	Notification of date construction commenced	This notification has been submitted for all affected facilities.
60.7(a)(3)	Notification of actual date of startup	This notification has been submitted for all affected facilities.
60.7(a)(4)	Notification of physical or operational change to an existing affected facility that may increase emissions.	This notification would be required in the event of a physical or operational change of an existing affected facility that may increase emissions. This requirement is included in Permit Condition 53.d.
60.7(a)(5)	Notification of the date upon which demonstration of CEMS performance commences.	Subpart GG does not require CEMS for the combustion turbines. However, PGE has obtained approval to use the CEMS in lieu of other NSPS monitoring. Therefore, this notification is required. The CEMS notification has been submitted for both combustion turbines. For the auxiliary boiler, subparts D and Db only require CEMS for NO _x because only natural gas is burned in the boiler. In addition, the NO _x CEMS is not required because the emissions are less than 70% of the standard and the annual capacity factor is less than 10%. If the annual capacity factor will increase above 10%, the permittee must install a NO _x CEMS and submit the required notification.
60.7(a)(6)	Notification of the anticipated date for conducting the opacity observations required by 60.11(e)(1).	This only applies to the auxiliary boiler and the initial performance test has been conducted.
60.7(a)(7)	Notification that Continuous Opacity Monitoring System (COMS) data will be used for determining compliance with opacity standards.	COMS are not required or used at the facility so this is not applicable.
60.7(b)	Records of startup/shutdown/malfunctions	This is an applicable requirement that is contained in Permit Condition 46.j.
60.7(c), 60.7(d), and 60.7(e)	Excess emissions reporting	These requirements are contained in Permit Condition 53. The NO _x CEMS on the combustion turbines was approved as an alternative to the water to fuel ratio monitoring when burning fuel oil, so the NSPS excess emissions reporting is only required when oil is burned in combustion turbine 1. The NO _x CEMS for the auxiliary boiler is not currently required because the capacity factor is less than 10%. Therefore, the NSPS excess emissions reporting is not currently required for the auxiliary boiler. All other CEMS are subject to state regulations, so they are subject to the state excess emissions reporting requirements in Permit Condition 47.
60.7(f)	CEMS records	The Title V recordkeeping requirement contained in Permit Condition 45 covers this requirement.
60.8	Performance tests	The initial performance tests for both combustion turbines have been completed.
60.11(b) and 60.11(e)	Opacity observation in conjunction with performance	This is not applicable because combustion turbine 1 and the auxiliary boiler have already been tested and combustion

Section	Requirement	Permit action
	test	turbine 2 is not subject to an NSPS opacity standard.
60.11(d)	Operate equipment with good air pollution control practices	This is included in Permit Condition 7.
60.11(g)	Credible evidence	This is included in General Condition G6.
60.12	Circumvention	This is included in Condition 7.
60.13	Monitoring requirements	This is included in the CEMS monitoring conditions.

21. NESHAPs (40 CFR Part 63): This is not a major source of HAPs, so the NESHAP for Combustion Turbines or Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, subpart YYY) is not applicable.
22. CAM (40 CFR Part 64): The Compliance Assurance Monitoring rules (CAM) in 40 CFR Part 64 and OAR 340-212-0200 through 340-212-0280 do not apply to this facility for the following reasons:
- 22.a. CAM does not apply to the auxiliary boiler because there are no add-on emission controls.
- 22.b. CAM does not apply to the combustion turbines because the control devices are used to comply with NO_x limits for which the permit requires a continuous compliance determination method (e.g., CEMS). [See exemption in OAR 340-212-0200(2)(F)]
- 22.c. All other emission units at the facility either have no control devices or the potential pre-controlled emissions are less than 100 tons per year.
23. Accidental Release Program (40 CFR Part 68): This facility is subject to the Accidental Release Program because ammonia is used in the Selective Catalytic Reduction control system on each combustion turbine. This program is not delegated to the DEQ so the requirements are incorporated by reference. The risk management plan (RMP) was submitted to EPA by the due date. The permittee must comply with the RMP and any other applicable requirements from 40 CFR Part 68.
24. Acid Rain Program (40 CFR Part 72): This facility is subject to the Acid Rain Program. The Acid Rain permit and statement of basis is attached to the Title V permit.

Insignificant Emissions Units

25. 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 opacity (20% 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.

PLANT SITE EMISSION LIMITS

26. Provided below is a summary of the baseline emissions rate, netting basis, plant site emission limits, and emissions capacity.

Pollutant	Baseline Emission Rate (tons/yr)	Netting Basis		Plant Site Emission Limit (PSEL)		
		Previous (tons/yr)	Proposed (tons/yr)	Previous (tons/yr)	Proposed (tons/yr)	Increase (tons/yr)
PM/PM ₁₀	0	48	48	48	48	0
CO	0	452	452	452	452	0
NO _x	0	287	287	287	287	0
SO ₂	0	0	0	39	39	0
VOC	0	0	0	39	39	0

- 26.a. This facility did not operate during the baseline period of 1977 or 1978 so the baseline emission rate is zero.
- 26.b. The netting basis was established during the PSD permitting action in 1995.
- 26.c. There are no changes to the PSEL.

SIGNIFICANT EMISSION RATE

27. The proposed PSEL is not greater than the previous netting basis as shown below.

Pollutant	SER	Increase over previous netting basis	Increase due to rule revisions	Increase due to physical changes or changes in the method of operation
PM	25	0	NA	NA
PM ₁₀	15	0	NA	NA
CO	100	0	NA	NA
NO _x	40	0	NA	NA
SO ₂	40	39	NA	39
VOC	40	39	13	26

HAZARDOUS AIR POLLUTANTS

28. Using emission factors from AP-42 and a source test for formaldehyde, the potential HAP emissions are calculated in attachment 1. The maximum emissions for a single HAP (Hexane) are estimated to be 5.5 tons per year and the maximum emissions for combined HAPs are 11.5 tons per year. As defined in OAR 340-200-0020, a major source of HAPs is one that has the potential to emit 10 or more tons of a single HAP or 25 or more tons of combined HAPs per year. Therefore, this facility is not a major source of hazardous air pollutant (HAP) emissions.

TOXIC AND FLAMMABLE SUBSTANCE USAGE

29. PGE reported that they use greater than 50,000 lbs of ammonia per year.

STRATOSPHERIC OZONE DEPLETING SUBSTANCES

30. PGE does not manufacture, sell, distribute, or use in the manufacturing of a product any stratospheric ozone-depleting substances. Therefore, the 1990 Clean Air Act, as amended, 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

31. The proposed permit is a renewal of the Oregon Title V Operating Permit issued on 5/14/03 and scheduled to expire on 05/01/08.
32. There are no other permits issued or required by the Department for this source.
33. This source is located in an area that is in attainment for all pollutants. This source is not located within 100 kilometers (62 miles) of a Class I air quality protection area.

COMPLIANCE HISTORY

34. The following inspections were conducted during the last permit term:

Date	Compliance status	Follow-up action
8/13/03	Out of compliance	Issued a Notice of Non-Compliance (see below)
9/14/05	In compliance	None
8/2/07	In compliance	None

35. DEQ issued Notice of Noncompliance AQ-ERB-03-10647 on August 29, 2003 for a NO_x exceedance that occurred on March 22, 2003 and for failing to provide timely notification of the excess emissions. These were both Class II violations. PGE initiated an internal incident report that included a root cause analysis and corrective actions. The corrective action included addition of an audible alarm on the CEMS which did not previously exist. Training was conducted to re-educate everyone that during load changes when daily calibrations are being done, ammonia feed must be controlled manually. No further corrective action was needed. A civil penalty was not assessed for these violations.
36. The DEQ did not receive any complaints about the facility operations during the previous permit term.

SOURCE TEST RESULTS

37. Provided below is a summary of emission tests performed on combustion turbine 1 during the last permit term:

Parameter/ Pollutant	Parameter	Test Date				
		10/14/03	9/15/04	8/16/05	8/2/06	8/7/07
O ₂	Avg. RM ² value, %	13.9	13.9	14	13.9	13.8
	RATA results:	0.6	--	---	---	---
	Absolute diff.	0.1	0.1	0.1	0	0
	Status	pass	pass	pass	pass	pass

² RM stands for "reference method" and RATA stands for "Relative Accuracy Test Audit"

Parameter/ Pollutant	Parameter	Test Date				
		10/14/03	9/15/04	8/16/05	8/2/06	8/7/07
CO	Avg. RM value, ppm @ 15% O _x	1.6	0.8	0.8	1.1	0.8
	RATA results:	1.8 std	2 std	2 std	3 std	3 std
	Absolute diff.	0.12	-0.3	-0.2	0.48	0.43
	Status	pass	pass	pass	pass	pass
NO _x	Avg. RM value, ppm @ 15% O _x	4.4	3.6	3.5	3.8	4
	RATA results:	5	11	17	11	1
	Absolute diff.	0.2	-0.4	-0.5	0.35	0
	Status	pass	pass	pass	pass	pass
NO _x	Avg. RM value, lb/MMBtu	0.016	0.013	0.013	0.014	0.015
	RATA results:	6.3	12	18	12	3
	Absolute diff.	0.001	-0.001	-0.002	0.00	0.00
	Status	pass	pass	pass	pass	pass

38. Provided below is a summary of emission tests performed on combustion turbine 2 during the last permit term:

Parameter/ Pollutant	Parameter	Test Date				
		7/15/03	9/14/04	8/17/05	8/3/06	8/8/07
O ₂	Avg. RM ³ value, %	13.5	13.8	13.2	13.5	13.3
	RATA results:	0.4	--	---	---	---
	Absolute diff.	0.03	0.03	0.2	-0.004	0.1
	Status	pass	pass	pass	pass	pass
CO	Avg. RM value, ppm @ 15% O _x	1.6	0.4	1.3	0.6	0.58
	RATA results:	3 std	2 std	1 std	1 std	2 std
	Absolute diff.	0.2	-0.2	0.1	0.001	0.22
	Status	pass	pass	pass	pass	pass
NO _x	Avg. RM value, ppm @ 15% O _x	4	4.1	3.7	3.8	3.1
	RATA results:	5.3	4	5	4	2
	Absolute diff.	0.2	0.1	-0.2	0.1	0.03
	Status	pass	pass	pass	pass	pass
NO _x	Avg. RM value, lb/MMBtu	0.015	0.015	0.013	0.014	0.011
	RATA results:	5	41624	418	12	3
	Absolute diff.	0.001	0.0004	-0.001	0.00	0.00
	Status	pass	pass	pass	pass	pass

³ RM stands for "reference method" and RATA stands for "Relative Accuracy Test Audit"

PUBLIC NOTICE

39. This permit was placed on public notice from May 23, 2008 to June 27, 2008. No comments were received in response to the Public Notice. A proposed permit has been sent to EPA for a 45 day review period. The Department may request and EPA may agree to an expedited review of 5 days if there were no substantive or adverse comments during the comment period.

If the EPA does not object in writing, any person may petition the EPA within 60 days after the expiration of 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 provided for in OAR 340-218-0210, 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.

ATTACHMENT 1: EMISSIONS DETAIL SHEET

Emissions Unit/Device	Fuel	Process Rate or Throughput		Emission Factor		Emissions ton/yr
		rate	units	rate	units	
Particulate Matter:						
CT1: 594 hours	Oil	8.20E+06	gal/yr	2.42	lb/1000 gal	9.9
CT1: 8166 hours	Natural gas	1.47E+10	ft3/hr	2.5	lb/MMft3	18.3
CT2: 8760 hours	Natural gas	1.57E+10	ft3/hr	2.5	lb/MMft3	19.7
AB:	Natural gas	6.08E+09	ft3/hr	5.62	lb/MMft3	17.1
PM Total						48
Carbon Monoxide (CO):						
CT1: 594 hours	Oil	8.20E+06	gal/yr	4.98	lb/1000 gal	20.4
CT1: 8166 hours	Natural gas	1.47E+10	ft3/hr	28.4	lb/MMft3	208.4
CT2: 8760 hours	Natural gas	1.57E+10	ft3/hr	28.4	lb/MMft3	223.5
AB	Natural gas	6.08E+09	ft3/hr	39.8	lb/MMft3	120.9
CO Total						452
Nitrogen Oxides (NOx):						
CT1: 594 hours	Oil	8.20E+06	gal/yr	8.18	lb/1000 gal	33.5
CT1: 8166 hours	Natural gas	1.47E+10	ft3/hr	16.7	lb/MMft3	122.5
CT2: 8760 hours	Natural gas	1.57E+10	ft3/hr	16.7	lb/MMft3	131.4
AB	Natural gas	6.08E+09	ft3/hr	48.4	lb/MMft3	147.0
NOx Total						287
Sulfur Dioxide (SO2):						
CT1: 594 hours	Oil	8.20E+06	gal/yr	7.25	lb/1000 gal	29.7
CT1: 8166 hours	Natural gas	1.47E+10	ft3/hr	0.64	lb/MMft3	4.7
CT2: 8760 hours	Natural gas	1.57E+10	ft3/hr	0.64	lb/MMft3	5.0
AB	Natural gas	6.08E+09	ft3/hr	0.64	lb/MMft3	1.9
SO2 Total						39
Volatile Organic Compounds (VOC):						
CT1: 594 hours	Oil	8.20E+06	gal/yr	0.21	lb/1000 gal	0.9
CT1: 8166 hours	Natural gas	1.47E+10	ft3/hr	0.83	lb/MMft3	6.1
CT2: 8760 hours	Natural gas	1.57E+10	ft3/hr	0.83	lb/MMft3	6.5
AB	Natural gas	6.08E+09	ft3/hr	4.2	lb/MMft3	12.8
VOC Total						13.5
Lead (Pb):						
CT1: 594 hours	Oil	8.20E+06	gal/yr	5.80E-05	lb/MMBtu	0.03

1. All of the emission factors are based on the manufacturer's data, except lead and VOC. The lead emission factor was taken from AP-42 (Table 3.1-7). The VOC emissions factor is based on actual test data.
2. The auxiliary boiler annual emissions are not included in the totals because it is operated in place of the combustion turbines.

Hazardous Air Pollutants (HAP emission factors for compounds shown in italics are ½ the detection limit)

Combustion Turbines – Natural Gas (30,466.8 million cubic feet per year for both turbines):

(AP-42 Table 3.1-3, except formaldehyde based on 1995 source test)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Emissions (tons/yr)
<i>1,3 Butadiene</i>	4.30E-07	4.39E-04	0.007
Acetaldehyde	4.00E-05	4.08E-02	0.622
Acrolein	6.40E-06	6.53E-03	0.099
Benzene	1.20E-05	1.22E-02	0.186
Ethylbenzene	3.20E-05	3.26E-02	0.497
Formaldehyde	3.50E-06	3.57E-03	0.054
Naphthalene	1.30E-06	1.33E-03	0.020
PAH	2.20E-06	2.24E-03	0.034
<i>Propylene Oxide</i>	2.90E-05	2.96E-02	0.451
Toluene	1.30E-04	1.33E-01	2.020
Xylenes	6.40E-05	6.53E-02	0.994
Turbines – natural gas subtotal			4.985

Combustion Turbine #1 – Distillate Oil (8,196.6 thousand gallons per year):

(AP-42 Tables 3.1-4 and 3.1-5)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Emissions (tons/yr)
<i>1,3 Butadiene</i>	1.60E-05	2.22E-03	0.009
Benzene	5.50E-05	7.65E-03	0.031
Formaldehyde	2.80E-04	3.89E-02	0.160
Naphthalene	3.50E-05	4.87E-03	0.020
PAH	4.00E-05	5.56E-03	0.023
<i>Arsenic</i>	1.10E-05	1.53E-03	0.006
<i>Beryllium</i>	3.10E-07	4.31E-05	0.000
Cadmium	4.80E-06	6.67E-04	0.003
Chromium	1.10E-05	1.53E-03	0.006
Lead	1.40E-05	1.95E-03	0.008
Manganese	7.90E-04	1.10E-01	0.450
Mercury	1.20E-06	1.67E-04	0.001
<i>Nickel</i>	4.60E-06	6.39E-04	0.003
<i>Selenium</i>	2.50E-05	3.48E-03	0.014
Turbine #1 – distillate oil subtotal			0.734

Auxiliary boiler – natural gas (6,079.4 million cubic feet per year)
(AP-42 tables 1.4-3 and 1.4-4)

Pollutant	Emission Factor (lb/MMcf)	Emissions (tons/yr)
Benzene	2.10E-03	0.006
Dichlorobenzene	1.20E-03	0.004
Formaldehyde	7.50E-02	0.228
Hexane	1.80E+00	5.471
Naphthalene	6.10E-04	0.002
Toluene	3.40E-03	0.010
POM	8.82E-05	0.000
Arsenic	2.00E-04	0.001
<i>Beryllium</i>	1.20E-05	0.000
Cadmium	1.10E-03	0.003
Chromium	1.40E-03	0.004
Cobalt	8.40E-05	0.000
Manganese	3.80E-04	0.001
Mercury	2.60E-04	0.001
Nickel	2.10E-03	0.006
<i>Selenium</i>	2.40E-05	0.000
Auxiliary boiler – natural gas subtotal		5.739

HAP summary:

Source	Total (tons/yr)
Turbines – natural gas	4.985
Turbine #1 – distillate oil	0.734
Auxiliary Boiler – natural gas	5.739
Total HAPs – all sources	11.458
Maximum single HAP (Hexane)	5.471

ATTACHMENT 2: EXPLANATION OF PSEL TERMS

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. 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 standard for styrene, but the 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 PM₁₀ 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. In addition, any source that elects to have a Basic, General, or Simple ACDP forfeits their baseline emission rate.

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 changed 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 baseline 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 but not subject to NSR, 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 subject to NSR, 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 PSEL can be used to establish the PTE but 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. Unassigned emissions are established during the first permit renewal after July 1, 2001. If the unassigned emissions are not used during the permit term, they are reduced to the significant emission rate during the next permit renewal.

Emission Reduction Credits are established by OAR 340, Division 268. Emission reduction credits are a portion of the netting basis. 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 converted to unassigned emissions.

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 basis 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.

