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

Source Information:

SIC	4911
NAICS	221112

Public Participation Category	III

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)	3/1
Emission fee report (due date)	3/1
SACC (due date)	3/1 and 7/30
NSPS semi-annual excess emissions report	1/30 and 7/30

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

Air Programs

NSPS (list subparts)	Db, KKKK
NESHAP (list subparts)	ZZZZ
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

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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
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane (greenhouse gas)
CMS	Continuous Monitoring System
CO	Carbon Monoxide
CO_2	Carbon Dioxide (greenhouse gas)
CO_2e	Carbon Dioxide Equivalent (greenhouse gases)
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
GHG	Greenhouse Gases
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
N_2O	Nitrous Oxide (greenhouse gas)
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
$PM_{2.5}$	Particulate Matter less than 2.5 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 on July 6, 2008 and scheduled to expire on July 1, 2013. A complete renewal application was submitted on June 29, 2012 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. The following revisions to the permit were made during the last permit term. These changes are included in the Title V permit renewal.

Permit Revision	Application Number	Date Issued	Description of Changes
Significant Modification	23913	5/13/10	The requirements of 40 CFR Part 60, Subpart KKKK were added to the permit because of modifications to the duct burners on combustion turbine 2
Significant Modification	25684	4/1/11	The requirements of 40 CFR Part 60, Subpart KKKK were added to the permit because of modifications to combustion turbine 1
Significant Modification	26060	7/11/11	Requirements for continuously monitoring NO_x emissions from the auxiliary boiler were added to the permit because PGE requested that the 10% capacity factor limit be removed from the permit.

4. 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	Facility Contact Person	Changes in personnel
1 through 8	1 through 8	No changes	EPA review and changes to general conditions
Table 2	Table 2	Deleted references to 60.333(a)(1) and 60.333(b) for CT1 and CT2; 60.44b(b)(4) for CT2; and 60.42(a)(1), 60.42(a)(2), and 60.44(c)(1) for AB. Added references to 60.4320(a) and 60.4330(a)(2) for CT1 and CT2; and 60.4320(b) for CT1.	The requirements of 40 CFR Subpart GG have been replaced with the requirements of 40 CFR Subpart KKKK due to modifications to the combustion turbines. In addition, the requirements of Subpart D should not have been included in the permit for the auxiliary boiler. These changes incorporate significant permit modifications listed above.
9 – 13	9 – 13	No changes	
14	14	Replaced the NSPS Subpart GG NO_x limits with the Subpart KKKK NO_x limits.	These changes incorporate significant permit modifications listed above.
15	15	No changes	
---	16 and 17	Deleted	The requirements from Subpart GG no longer apply. The requirement from

New Condition Number	Old Condition Number	Change	Reason
			Subpart D should not have been included in the permit. The auxiliary boiler is not subject to Subpart D.
16	18	No changes	
---	19	Deleted	The requirement form Subpart D should not have been included in the permit. The auxiliary boiler is not subject to Subpart D.
17	20	The 10% capacity factor limit was removed and the CEMS requirement added.	This incorporates the significant permit modification issued on 7/1/11.
18	21	No changes	
19	---	Added the NESHAP requirement for stationary CI emergency engines	This is a new requirement for existing emergency fire pump engines.
20	22	Add PSEL for $PM_{2.5}$ and GHG	These are new regulated pollutants.
21	23	Minor changes to "permitted emissions" for purposes of fees.	The PM_{10} emission factor was corrected.
22	24	Replace with current version from DEQ model permit	DEQ review of Title V requirements.
23	25	No changes	
24	---	Added NSPS Subpart KKKK testing requirements.	This incorporates the significant permit modifications listed above.
25 – 34	26 – 35	No changes	
35	36	Added NSPS Subpart KKKK monitoring requirements	This incorporates the significant permit modifications listed above.
36 and 37	37 and 38	No changes	
38	39	Replaced NSPS Subpart GG fuel sulfur monitoring requirements with Subpart KKKK fuel sulfur monitoring requirements	This incorporates the significant permit modifications listed above.
39	40	The NSPS Subpart Db capacity factor limit was removed and a CEMS requirement added.	This incorporates the significant permit modification issued on 7/1/11.
40	41	Updated PM_{10} and $PM_{2.5}$ emission factors	Correction
41 – 44	42 – 45	No changes	
45	46	Added Condition 44.k to specify the recordkeeping for the auxiliary boiler CEMS	This incorporates the significant permit modification issued on 7/1/11.
46	47	Revise 45.e to allow PGE submit monthly logs of startup/shutdown events rather than submitting a notification for each event.	Paper work reduction
47 – 49	48 – 50	No changes	
50	51	Changed the due date for the annual report to 3/1	PGE requested this change so the reporting dates for the Coyote Springs Plant and Boardman Plant would be the same.
51	52	No changes	
52	53	Changed citations to NSPS Subpart KKKK, removed the requirement for quarterly capacity factor reports.	This incorporates the significant permit modifications listed above.

New Condition Number	Old Condition Number	Change	Reason
53	54	Updated the non-applicability section based on the changes at the facility.	Subpart GG is no longer applicable to the turbines and Subpart KKKK is now applicable.
G1 – G29	G1 – G28	No changes	

PERMITTEE IDENTIFICATION

5. 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

6. 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.

7. 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.

EMISSIONS UNIT AND POLLUTION CONTROL DEVICE IDENTIFICATION

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

ID#	Description
OS1	Plant operating scenario
	Device\Process IDs:
CT1.DV	Combustion Turbine 1
CT2.DV	Combustion Turbine 2
AB.DV	Auxiliary Boiler
	Control Device IDs:
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.
	Emission Unit IDs:
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)
	Compliance Demonstration Point IDs:
CT1S.CDP	Combustion Turbine 1 stack
CT2S.CDP	Combustion Turbine 2 stack
ABS.CDP	Auxiliary Boiler Package stack

	Other IDs used at the plant
CTG	Combustion Turbine Generator
HRSG	Heat Recovery Steam Generator
PNG	Pipeline Natural Gas
STG	Steam Turbine Generator

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

9.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.

9.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.

9.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.

9.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.

9.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.

10. 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

11. 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 29.

12. 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 29). 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.

13. 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 33).

14. 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 31). Any violations must be documented and reported to the Department.

15. 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 grains[1] 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 31).

16. Particulate matter grain loading limit for boilers (OAR 340-226-0210(2)) – Permit Condition 16: 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 30).

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:

17. 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 30).

18. 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.

19. 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% O_2 and 30 lbs/hr as a 24-hour rolling average while

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

burning natural gas; and, 15 ppm @ 15% O_2 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 35).

20. <u>Carbon monoxide emissions limits (1995 ACDP, Condition 5) – Permit Condition 15</u>: Carbon monoxide emissions from the combustion turbines are limited to 15 ppm @15% O_2 and 51 lbs/hr as an 8-hour rolling average while burning natural gas; and, 20 ppm @ 15% O_2 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 37).

Federal Requirements

21. <u>New Source Performance Standards (40 CFR Part 60):</u>

21.a. The combustion turbines were originally subject to 40 CFR Subpart GG, but due to modifications to the turbines, they are now both subject to 40 CFR Subpart KKKK. The NO_x limit is 15 ppm corrected to 15% O_2 while burning natural gas; or, for CT1, 42 ppm when burning fuel oil. [60.4320(a) and (b)] The sulfur dioxide limits for both turbines is 0.060 lb/MMBtu heat input. [60.4330(a)(2)] The existing CEMS on CT1 and CT2 are used to determine compliance with the NO_x limits (Condition 35). Fuel sampling and analysis is used to determine compliance with the SO_2 emissions limit (Condition 38).

21.b. 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 Db. Since the auxiliary boiler only burns natural gas, it is not subject to the PM, opacity, and SO_2 standards in Subpart Db. It is subject to the NO_x standard in Subpart Db (Condition 17). The previous permit included a 10% limit on the capacity factor so a CEMS was not required. However, PGE requested that the 10% limit be removed and the CEMS requirement be added to the permit (Condition 39).

Summary of New Source Performance Standards:

22. A summary of the Subpart KKKK requirements and their applicability to the combustion turbines is provided below.

Subpart KKKK Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4305(a)	Applicability	Yes	The combustion turbines have been modified making them subject to Subpart KKKK.
60.4305(b)	Subpart Db and GG exemption	Yes	
60.4315	Regulated pollutants (NO_x and SO_2)	Yes	
60.4320(a)	NO_x emission limits	Yes	The limits in Table 1 for new, modified or reconstructed turbines greater than 850 MMBtu/h heat input apply to the combustion turbines.
60/4320(b)	Provisions for two or more turbines serving a single generator	No	Each turbine serves only one generator.
60.4325	Emission limits for multiple fuels	No	Natural gas or oil can be burned in CT1, but not at the same time. Only natural is burned in CT2.
60.4330(a)(1)	SO_2 emission limit based on power output	No	PGE proposed to comply with the limit based on heat input.
60.4330(a)(2)	SO_2 emission limit based on heat input	Yes	The limit is 0.060 lb/MMBtu heat input.
60.4330(b)	Limits for non-continental areas	No	The facility is not located in the specified area.
60.4333(a)	Good air pollution control practices	Yes	
60.4333(b)	Provisions for common steam header for more than on combustion turbine	No	There is only one heat recovery steam generator unit connected to each combustion turbine.

Subpart KKKK Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4335	Compliance provisions for water or steam injection systems	No	Water or steam injection is not used to control NO_x emissions from the combustion turbines.
60.4340(a)	Performance testing for demonstrating compliance with the emissions limits	No	A CEMS will be used for monitoring compliance instead of annual performance tests.
60.4340(b)(1)	CEMS	Yes	
60.4340(b)(2)	Continuous parameter monitoring	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4345	CEMS requirements	Yes	
60.4350	CEMS excess emissions	Yes, except 60.4350(f)(1) and (3), and (g)	Provisions for simple cycle and mechanical drive are not applicable.
60.4355	Parameter monitoring plan	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4360	Total fuel sulfur monitoring	No	PGE will comply with 60.4365 instead.
60.4365(a)	Tariff	Yes	
60.4365(b)	Representative fuel sampling data	No	PGE will use current tariff.
60.4370	Frequency of fuel sulfur content monitoring	No	PGE will use current tariff.
60.4375(a)	Reports for parameter monitoring and annual performance tests	No	PGE will be monitoring compliance with a CEMS.
60.4380(a)	Excess emissions reports when using water or steam injection	No	Water or steam injection is not used to control NO_x emissions.
60.4380(b)	CEMS excess emission reports	Yes	Defines excess emissions, monitoring downtime, and clarifies that excess emissions are based on the highest emissions standard if there are multiple emissions standards (e.g., ppm and lb/MWh).
60.4380(c)	Excess emissions reports for parameter monitoring	No	PGE will be monitoring compliance with a CEMS.
60.4385	Excess emissions for fuel sulfur monitoring	No	PGE will use current tariff.
60.4390	Reporting requirements for emergency or research combustion turbines	No	
60.4395	When are reports due	Yes	Reports must be postmarked by the 30^{th} day following the end of each 6-month period.
60.4400	Initial and annual performance test for NO_x	No	A CEMS will be used for monitoring compliance.
60.4405	Initial performance test if using a NO_x CEMS	Yes	Use RATA to satisfy requirements of 40 CFR 60.8.
60.4410	Establishing valid parameter ranges for NO_x	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4415(a)(1)	Initial and subsequent performance tests for SO_2	Yes	Collect and analyze a fuel sample annually.
60.4415(a)(2) and (3)	Stack test for SO_2	No	PGE will use option 1 instead of options 2 and 3.

23. A summary of the Subpart Db requirements and their applicability to the auxiliary boiler is provided below.

Subpart Db Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.40b	Applicability	Yes	The auxiliary boiler has a heat input greater than 100 MMBtu/hr and commenced construction after June 19, 1986.
60.42b	Sulfur dioxide (SO_2) standards	No	The auxiliary boiler burns only natural gas. There are no SO_2 standards for natural gas-fired boilers.
60.43b	Particulate matter (PM) standards	No	The auxiliary boiler burns only natural gas. There are no PM standards for natural gas-fired boilers.
60.44b	Nitrogen oxides (NO_x) standards	Yes	The limit for high heat release natural gas-fired boilers in 60.44b(a)(1)(ii) is applicable, but none of the other limits or standards in 60.44b are applicable.
60.45b	Compliance and performance test methods and procedures for SO_2	No	These requirements do not apply because the auxiliary boiler is not subject to any SO_2 standards.
60.46b	Compliance and performance test methods and procedures for PM and NO_x	Yes	The requirements in 60.46b(e)(1) and (3) apply, but the other requirements in 60.46b do not apply because the auxiliary boiler is not subject to any PM standards.
60.47b	Emission monitoring for SO_2	No	These requirements do not apply because the auxiliary boiler is not subject to any SO_2 standards.
60.48b	Emission monitoring for PM and NO_x	Yes	The NO_x CEMS requirements in 60.48b(c) through (f) apply, but the other requirements in 60.48b do not apply because the auxiliary boiler is not subject to any PM standards and PGE is not using the predictive NO_x emissions monitoring option.
60.49b	Reporting and recordkeeping requirements	Yes	The requirements of 60.49b(b), (g), (h) and (v) that apply to NO_x monitoring are applicable, but the other requirements for SO_2 and opacity monitoring do not apply.

23.a. 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 was required and was submitted. This requirement is included in Permit Condition 51.d.
60.7(a)(5)	Notification of the date upon which demonstration of CEMS performance commences.	A compliance report was submitted providing notification of CEMS certification.
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 44.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 43 covers this requirement.
60.8	Performance tests	The initial performance tests for both combustion turbines and auxiliary boiler have been completed.
60.11(b) and 60.11(e)	Opacity observation in conjunction with performance test	This is not applicable because combustion turbine 1 and the auxiliary boiler have already been tested and combustion 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.

24. NESHAPs (40 CFR Part 63): This facility has been evaluated for the following National Emissions Standards for Hazardous Air Pollutants (NESHAP).

    24.a. This is not a major source of hazardous air pollutants (HAPs), so the NESHAP for Combustion Turbines or Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, Subparts YYY and DDDDD) are not applicable.
    24.b. The source only has a natural gas fired boiler, so it is not subject to the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters located at area sources of HAPs (40 CFR, Part 63, Subpart JJJJJJ).
    24.c. This facility is an area source of HAPs with an emergency stationary Reciprocal Internal Combustion Engine (RICE) used to pump water in case of fire and is subject to 40 CFR, Part 63, Subpart ZZZZ requirements.

25. 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:

    25.a. CAM does not apply to the auxiliary boiler because there are no add-on emission controls.
    25.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)]
    25.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.

26. 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.

27. 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

28. 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.

29. Although considered a categorically insignificant emission unit, the stationary fire water pump emergency engine is subject to 40 CFR Part 63, Subpart ZZZZ. The work practice requirements have been included in the permit in Condition 19.

PLANT SITE EMISSION LIMITS

30. Provided below is a summary of the baseline emission rates, 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)
$PM/PM_{10}/PM_{2.5}$	0	48	48	48	48	0
SO_2	0	0	0	39	39	0
NO_x	0	287	287	287	287	0
CO	0	452	452	452	452	0
VOC	0	0	0	39	39	0
GHG (CO_2e)	1,518,000	NA	1,518,000	NA	1,916,000	NA

30.a. This facility did not operate during the baseline period of 1977 or 1978 so the baseline emission rate is zero for PM, PM_{10}, SO_2, NO_x, CO and VOC. $PM_{2.5}$ and GHG are new regulated pollutants. The rules do not require that a baseline emission rate be established for $PM_{2.5}$. The baseline emission rate for GHG are the actual emissions during any 12-consecutive month period between 1/1/00 and 12/31/10. PGE selected June 2007 through May 2008 as the baseline period. The actual emission during the baseline period was 1,518,000 tons on a carbon dioxide equivalent (CO_2e) basis.

30.b. The netting basis for PM, PM_{10}, NO_x and CO were established during the PSD permitting action in 1995. A netting basis was not established for SO_2 and VOC because the actual emissions are less than the significant emission rate and the pollutants were not subject to PSD. For $PM_{2.5}$, the rules specify that the netting basis is equal to $PM_{2.5}$ fraction of the PM_{10} netting basis in effect on 5/1/11. The $PM_{2.5}$ fraction of PM_{10} is considered to be 1.0. Therefore, the $PM_{2.5}$ netting basis is equal to the PM_{10} netting basis. The netting basis for GHG is equal to the baseline emission rate as specified in the rules. [see definition of 'baseline period', 'baseline emission rate', and 'netting basis' in OAR 340-200-0020]

30.c. There are no changes to the PSELs, except that PSELs have been added for $PM_{2.5}$ and GHG. The PSEL for $PM_{2.5}$ is equal to the $PM_{2.5}$ fraction of PM_{10} PSEL in effect on 5/1/11, as specified in the rules. The $PM_{2.5}$ fraction of PM_{10} is considered to be 1.0. Therefore, the $PM_{2.5}$ PSEL is equal to the PM_{10} PSEL. For GHG, the PSEL is equal to the netting basis unless the permittee requests an increase in accordance with OAR 340-222-0041(3). PGE has requested a PSEL equal to the source's potential to emit in order to be allowed to utilize the existing capacity of the turbines. This increase is approved without further review since there is no ambient air quality standard for GHG.

Significant Emission Rate

31. Except for GHG, the proposed PSELs are not greater than the netting basis by more than a significant emissions rate (SER), as shown below. For GHG, the increase is greater than the SER, but the increase is allowed under the rules because the increase in not due to a physical change or change in the method of operation and there is no ambient air quality standard for GHG.

Pollutant	SER	Increase Over Previous Netting Basis	Increase Due to Rule Revisions (generic PSEL)	Increase Due to Physical Changes or Changes in the Method of Operation	Increase Due to Utilizing Existing Capacity (no physical changes)
PM	25	0	NA	NA	NA
PM_{10}	15	0	NA	NA	NA
$PM_{2.5}$	10	NA	NA	NA	NA
SO_2	40	39	21	18	0
NO_x	40	0	NA	NA	NA
CO	100	0	NA	NA	NA
VOC	40	39	26	13	0
GHG	75,000	398,000	NA	0	398,000

HAZARDOUS AIR POLLUTANTS

32. 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

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

Stratospheric Ozone Depleting Substances

34. 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

35. The proposed permit is a renewal of the Oregon Title V Operating Permit issued on 7/16/08 and scheduled to expire on 07/01/13.

36. There are no other permits issued or required by the Department for this source.

37. 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

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

Date	Compliance Status	Follow-Up Action
9/15/09	In compliance	None
9/28/11	In compliance	None

39. There were no enforcement actions during the previous permit term.

40. DEQ did not receive any complaints about the facility operations during the previous permit term.

SOURCE TESTING

41. The current permit required testing at least annually to verify the accuracy of the continuous emissions monitoring systems (CEMS). These tests are referred to as relative accuracy test audits (RATA) that are conducted by an independent third party using approved test methods and procedures. The CEMS at the PGE Coyote Springs plant have successfully passed the audit each time the RATA was conducted. The requirement for annual RATAs will remain in the proposed permit.

PUBLIC NOTICE

42. This permit was placed on public notice from April 5, 2013 to May 10, 2013. No one requested a hearing, but DEQ did receive comments from two people. The comments and DEQ’s responses are attached to this review report in Attachment 2. DEQ did not make any changes to the draft permit in response to the comments. The proposed permit will be sent to EPA for a 45 day review period. The Department will request and EPA may agree to an expedited review of 5 days.

    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 SHEETS

Emissions Unit/ Device	Fuel	Process Rate or Throughput		Emission Factor		Emissions
		Rate	Units	Rate	Units	ton/yr
Particulate Matter (PM, PM_{10}, $PM_{2.5}$):						
CT1: 160 hours	Oil	2.21E+06	gal/yr	2.42	lb/1000 gal	9.9
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	2.5	lb/MMft3	18.3
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	2.5	lb/MMft3	19.7
AB:	Natural gas	6.08E+09	ft3/yr	5.62	lb/MMft3	17.1
PM Total						**48**
Carbon Monoxide (CO):						
CT1: 160 hours	Oil	2.21E+06	gal/yr	4.98	lb/1000 gal	20.4
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	28.4	lb/MMft3	208.4
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	28.4	lb/MMft3	223.5
AB	Natural gas	6.08E+09	ft3/yr	39.8	lb/MMft3	120.9
CO Total						**452**
Nitrogen Oxides (NO_x):						
CT1: 160 hours	Oil	2.21E+06	gal/yr	8.18	lb/1000 gal	33.5
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	16.7	lb/MMft3	122.5
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	16.7	lb/MMft3	131.4
AB	Natural gas	6.08E+09	ft3/yr	48.4	lb/MMft3	147.0
NO_x Total						**287**
Sulfur Dioxide (SO_2):						
CT1: 160 hours	Oil	2.21E+06	gal/yr	7.25	lb/1000 gal	29.7
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	0.64	lb/MMft3	4.7
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	0.64	lb/MMft3	5.0
AB	Natural gas	6.08E+09	ft3/yr	0.64	lb/MMft3	1.9
SO_2 Total						**39**
Volatile Organic Compounds (VOC):						
CT1: 160 hours	Oil	2.21E+06	gal/yr	0.21	lb/1000 gal	0.9
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	0.83	lb/MMft3	6.1
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	0.83	lb/MMft3	6.5
AB	Natural gas	6.08E+09	ft3/yr	4.2	lb/MMft3	12.8
VOC Total						**13.5**
Lead (Pb):						
CT#1: 160 hours	Oil	8.20E+06	gal/yr	5.80E-05	lb/MMBtu	**0.03**
Greenhouse Gases						
CT1: 160 hours	Oil	2.21E+06	gal/yr	22.6	lb/gal	24,923
CT1: 8450 hours	Natural gas	1.57E+10	ft3/yr	0.12	lb/ft3	946,743
CT2: 8760 hours	Natural gas	1.57E+10	ft3/yr	0.12	lb/ft3	944,460,
AB	Natural gas	6.08E+09	ft3/yr	0.12	lb/ft3	365,617
GHG Total (CO_2e)						**1,916,126**

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 natural gas usage for the CT1 and CT2 includes the gas usage in the duct burners.
3. 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 (31,466.8 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)
1,3 Butadiene	4.30E-07	4.39E-04	0.007
Acetaldehyde	4.00E-05	4.08E-02	0.642
Acrolein	6.40E-06	6.53E-03	0.103
Benzene	1.20E-05	1.22E-02	0.192
Ethylbenzene	3.20E-05	3.26E-02	0.513
Formaldehyde	3.50E-06	3.57E-03	0.056
Naphthalene	1.30E-06	1.33E-03	0.021
PAH	2.20E-06	2.24E-03	0.035
Propylene Oxide	2.90E-05	2.96E-02	0.465
Toluene	1.30E-04	1.33E-01	2.085
Xylenes	6.40E-05	6.53E-02	1.026
Turbines – natural gas subtotal			**5.145**

Combustion Turbine #1 – Distillate Oil (2,207.8 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)
1,3 Butadiene	1.60E-05	2.22E-03	0.002
Benzene	5.50E-05	7.65E-03	0.008
Formaldehyde	2.80E-04	3.89E-02	0.043
Naphthalene	3.50E-05	4.87E-03	0.005
PAH	4.00E-05	5.56E-03	0.006
Arsenic	1.10E-05	1.53E-03	0.002
Beryllium	3.10E-07	4.31E-05	0.000
Cadmium	4.80E-06	6.67E-04	0.001
Chromium	1.10E-05	1.53E-03	0.002
Lead	1.40E-05	1.95E-03	0.002
Manganese	7.90E-04	1.10E-01	0.121
Mercury	1.20E-06	1.67E-04	0.000
Nickel	4.60E-06	6.39E-04	0.001
Selenium	2.50E-05	3.48E-03	0.004
Turbine #1 – distillate oil subtotal			**0.198**

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
Beryllium	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
Selenium	2.40E-05	0.000
Auxiliary boiler – natural gas subtotal		**5.739**

HAP Summary:

Source	Total (tons/yr)
Turbines – natural gas	5.145
Turbine #1 – distillate oil	0.198
Auxiliary Boiler – natural gas	5.739
Total HAPs – all sources	11.082
Maximum Single HAP (Hexane)	5.471

ATTACHMENT 2: RESPONSE TO COMMENTS

COMMENT 1:

FRIENDS OF THE COLUMBIA GORGE
SUBMITTED VIA E-MAIL

May 10, 2013

Nancy Swofford, Permit Coordinator
DEQ
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
swofford.nancy@deq.state.or.us

Re: Public Comment on PGE's Renewal of the Coyote Springs Plant's Title V Operating Permit.

Dear Ms. Swofford:

Friends of the Columbia Gorge ("Friends") has reviewed and would like to comment on the PGE's application to the Department of Environmental Quality ("DEQ") to renew the Coyote Springs Plant's Title V operation permit. Friends is a non-profit organization with members in approximately 5,000 households dedicated to protecting and enhancing the resources of the Columbia River Gorge. Our membership includes hundreds of citizens who reside in the six counties within the Columbia River Gorge National Scenic Area.

Friends is concerned about the potential impacts of the proposed gas combustion energy facility on the scenic, natural, recreational, and cultural resources of the Columbia River Gorge. DEQ's prior permit does not appear to have address potential impacts of air pollution on visibility in the Columbia River Gorge National Scenic Area and the impacts of deposition on protected resources, such as Native American cultural resource sites. Based on these concerns DEQ may need to modify permit conditions to reduce the cumulative adverse impacts of the Coyote Springs Plant.

I. Coyote Springs Plant Contributes to Adverse Impacts to Air Quality in the Columbia River Gorge National Scenic Area

The Columbia River Gorge National Scenic Area is already severely impaired by air pollution, especially nitrogen oxides (NOx) and particulate pollution. The Gorge now stands among the most polluted places in the country, including Pittsburgh and Los Angeles. A 2005 joint study by the U.S. Forest Service and National Park Service studied twelve federally managed areas around the Westand found that the Columbia River Gorge National Scenic Area and Sequoia National Park had by far the worst "annual standard visual range[s]" of the twelve areas in the study.[1] Similarly, a 2000 Forest Service study of air quality monitoring data from 39 federally managed "visibility protected" areas in the West found that the Scenic Area has "the highest levels of haze" and "the sixth worst visibility pollution of these areas."[2] Gorge air quality has been monitored for the last twenty years.

The Forest Service has documented that visibility impairment occurs on at least 95% of the days that have been monitored.[3] Data gathered from U.S Forest Service IMPROVE sites in the Gorge show that air quality is not improving.

Deposition of pollutants also has profound negative impacts on ecosystems. Studies demonstrate that in the Western United States, some aquatic and terrestrial plant and microbial communities are significantly altered by nitrogen deposition.[4] Metals, sulfur and nitrogen concentrations in lichen tissue found in the Gorge are comparable to that found in lichen tissue sampled in urban areas. Acid deposition in the eastern Gorge is also threatening Native American cultural resources. Nitrogen deposition rates in the Gorge are comparable to the most polluted areas in the United States. The Gorge does not deserve this bombardment on its ecological and cultural resources.

Particulate matter pollution also threatens human health and welfare. In fact, when reviewing the National Ambient Air Quality Standards for PM2.5, EPA found that there is no level of particulate matter pollution at which there are no human health effects. According to EPA, fine particulate matter pollution causes a variety of adverse health effects, including premature death, heart attacks, strokes, birth defects, and asthma attacks.[5] Even low levels of PM can cause low birth weights, damage lung function, and increase risks of heart attack and premature death. Studies reviewed by EPA revealed a linear or almost linear relationship between diseases like cancer and the amount of fine particulate matter in the ambient air.[6] Consequently, any particulate matter contamination has adverse health effects.

Based on concern over Gorge air quality, in 2001 the Forest Service and the Columbia River Gorge Commission amended the Management Plan for the National Scenic to require development of an air quality strategy in order to protect and enhance air quality and other protected resources in the National Scenic Area. CRGNSA Management Plan at I-3-32–33. This new information demonstrates the need for DEQ to address impacts of the renewal of the Coyote Springs Plant’s Title V permit to prevent ongoing adverse impacts to the National Scenic Area.

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[1] Mark Fenn, USDA Forest Service et al., *Why federal land managers in the Northwest are concerned about nitrogen emissions*, at 10 (Dec. 2004).
[2] Arthur Carroll, USDA Forest Service, Letter to Columbia River Gorge Commission, at 3 & attach. 3 (Feb. 7, 2000).
[3] Robert Bachman, USDA Forest Service, *A summary of recent information from several sources indicating significant increases in nitrogen in the form of ammonia and ammonium nitrate in the Eastern Columbia River Gorge and the Columbia Basin*, at 2 (June 24, 2005).
[4] *See* Mark E. Fenn, et al, Ecological Effects of Nitrogen Deposition in the Western United States, BioScience Vol. 53:4, Apr. 2003, available at http://www.bioone.org/doi/abs/
[5] 71 Fed. Reg. 2620, 2627–36 (Jan. 17, 2006).
[6] *Id*.

II. Columbia River Gorge National Scenic Area Act

State laws requires that "a state agency shall take no action that must be reviewed for compatibility with . . . [a] land use regulation in the Columbia River Gorge National Scenic Area until the agency determines through written findings that the action is consistent with the purposes and standards as provided in sections 3 and 6(d) of the Columbia River Gorge National Scenic Area Act, P.L. 99-663, and the scenic area management plan." ORS 196.110(2).

DEQ must ensure that the project is consistent with the Scenic Area Act and the Management Plan. The Management Plan for the Columbia River Gorge National Scenic Area states "air quality shall be protected and enhanced, consistent with the purposes of the Scenic Area Act." NSA Management Plan at I-3-32. To carry out this mandate, the Oregon DEQ, Southwest Clean Air Agency, U.S. Forest Service and Columbia River Gorge Commission are charged with the responsibility of adopting a comprehensive air quality strategy for the Columbia River Gorge that addresses all sources of air pollution. The Gorge Commission recently approved the *Columbia River Gorge Air Study and Strategy* (September 2011) ("Gorge Air Quality Strategy").

The proposed permit renewal would likely contribute to existing air quality impairment. DEQ must ensure that proposed project would not cause adverse impacts to protected resources in the Columbia River Gorge National Scenic Area.

III. DEQ's Air Quality Program and Coordination with EFSC

The proposed permit would authorize the operation of an energy facility that would emit pollutants including nitrogen dioxide (NO2), sulfur dioxide (SO2), and fine particulates (PM2.5 and PM10). DEQ cannot knowingly issue a permit that allows a violation of an air quality standard. OAR 340-202-0050(2) states that

> if a source or combination of sources are singularly responsible for a violation of ambient air quality standards in a particular area, it may be appropriate to impose emission standards that are more stringent than those otherwise applied to the class of sources involved. Similarly, proposed construction of new sources or expansions of existing sources, that may prevent or interfere with the attainment and maintenance of ambient air quality standards are grounds for issuing an order prohibiting such proposed construction as authorized by ORS 468A.055 and pursuant to OAR 340-210-0200 through 340-210-0220, and OAR 340-218-0190.

DEQ's visibility impacts analysis regulations require DEQ to encourage the owner or operator of a facility "to demonstrate that these same emission increases or decreases will not cause or contribute to significant impairment of visibility on the Columbia River Gorge National Scenic Area (if it is affected by the source)." OAR 340-225-0070(3)(a). It appears that the air emissions of the Coyote Springs Plant were not modeled during the first permit review and have not been modeled for the renewal of the Title V permit.

DEQ must demonstrate that is has encouraged PGE to demonstrate that its emission will not cause or contribute to significant impairment of visibility in the National Scenic Area. If DEQ has not taken action to encourage PGE to perform such modeling, DEQ should delay issuing a permit until such action is taken.

DEQ's encouragement of the analysis of the effects of emissions from this facility on the Columbia River Gorge could inform EFSC's review for compliance with energy facility siting standards. EFSC's siting guidelines require EFSC to ensure that the project will "not likely result in significant adverse impact to the . . . . Columbia River Gorge National Scenic Area." OAR 345-022-0040. This finding is required to be based on the application (or application amendment), which must provide:

> [i]nformation about the proposed facility's impact on protected areas, providing evidence to support a finding by the Council as required by OAR 345-022-0040, including . . . [a] description of significant potential impacts of the proposed facility, if any, on the protected areas including, but not limited to, potential impacts such as: *Visual impacts from air emissions resulting from facility construction or operation*, including, but not limited to, impacts on Class 1 Areas as described in OAR 340-204-0050.

OAR 345-021-0010(1)(l)(C)(vi) (emphasis added). In addition, EFSC "must find that the design, construction, operation and retirement of the facility, taking into account mitigation, are not likely to result in significant adverse impact to scenic and aesthetic values identified as important in applicable federal land use management plans or in local land use plans in the analysis area described in the project order." OAR 345-022-0080.

DEQ must ensure that the proposed permit would not violate any air quality standards. In addition, DEQ should consult with EFSC to determine if the continued operation of the plant would cause any adverse impacts to protected resources in the National Scenic Area. DEQ should provide analysis and recommendations on potential impacts that warrant additional conditions of approval or denial under EFSC's siting regulations.

IV. Climate Change Impacts

Friends is also concerned about the potential significant impacts of climate change on the National Scenic Area. The Coyote Springs Plant is estimated to produce 1,916,000 tons of greenhouse gas emissions per year. This will contribute to ongoing cumulative adverse impacts of climate change on Gorge resources. Consistent with DEQ's goals and policies, DEQ must address potential climate change impacts of air pollution and ensure that the facility would not adversely affect Gorge air quality and other protected resources.[7]

EFSC also has adopted regulations that require a energy facilities to off-set greenhouse gas emissions. *See e.g.*, OAR 345 Division 24. These regulations include standards limiting the amount air pollution discharged from the facility and standards requiring the applicant off-set greenhouse gas emissions. OAR 345-024-0550(1), (2), and (3). DEQ must coordinate with ESFC to ensure that its air quality permits and any CO2 emission standards are consistent with EFSC's regulatory requirements.

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[7] Oregon DEQ, Climate Change, http://www.deq.state.or.us/aq/climate/index.htm (last visited February 4, 2013).

V. Conclusion

Thank you for this opportunity to comment. Sincerely,

Richard Till
Conservation Legal Advocate

cc, via e-mail:
Chris Green, Siting Officer, Oregon Department of Energy
Rick Graw, USDA Forest Service
Lynn Burditt, Area Manager, USDA Forest Service, CRGNSA Office

RESPONSE 1:

May 17, 2013

Richard Till
Conservation Legal Advocate
Friends of the Columbia Gorge

RE: PGE Coyote Springs Oregon Title V Operating Permit Renewal Comments (permit 25-0031-TV-0I)

Mr. Till:

DEQ received your comments on the draft Oregon Title V Permit renewal for PGE Coyote Springs on May 10, 2013. Provided below is a response to your comments.

Based on your comments, I believe that a brief overview of DEQ's Air Quality Permitting program (and federal Clean Air Act) would be helpful for understanding the responses I have provided below, as well as help you formulate comments on Title V permits in the future.

The Clean Air Act requires states to develop State Implementation Plans (SIP) for implementing the requirements of the Clean Air Act[1]. EPA rules[2] spell out what must be included in the plans. If the plans meet the requirements, EPA will approve the plans and the state or permitting authority is then authorized to implement the plan. The SIP must include provisions for issuing pre-construction permits for major sources and major modifications at major sources[3]. Pre-construction permits are issued to prevent violations of the National Ambient Air Quality Standards (NAAQS) and prevent significant deterioration of air quality due to a proposed source's emission increases when a source is located within an area that is either classified as in attainment with NAAQS or is otherwise "unclassified". These permits are referred to as Prevention of Significant Deterioration (PSD) permits. DEQ issues the permits under the authority of an Air Contaminant Discharge Permit (ACDP) program[4] and New Source Review program[5] that both have been approved by EPA as part of the SIP.

PSD permits are only issued if the owner or operator of a source demonstrates to the satisfaction of DEQ that the emissions increases will not cause an adverse impact on air quality, including visibility[6]. The PSD program also requires the owner or operator to use the Best Available Control Technology (BACT) to minimize pollutant emissions to the extent practicable. Once the source is permitted, the source is not required to repeat the PSD permitting action unless the source cannot comply with the requirements or the source is modified such that there will be a significant increase in emissions.

The Title V permitting program was established when the Clean Air Act was revised in 1990[7]. Each state or permitting authority was required to develop a Title V permitting program separate from the SIP and have it

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[1] Section 110
[2] 40 CFR Part 52
[3] 40 CFR 52.21
[4] OAR 340, Division 216
[5] OAR 340, Division 224, specifically OAR 340-224-0070 for PSD permit actions
[6] OAR 340-225-0050, 340-225-0060, and 340-225-0070
[7] Sections 500 through 507

approved by EPA. DEQ developed the program[8] within the deadlines set by the Clean Air Act and the program has been fully approved by EPA. DEQ's Title V program is an "operating" permit program designed to ensure that sources comply with all [air quality] requirements applicable to the source, including any requirements that are established under the PSD permitting program. The program is not designed, by itself, to establish additional requirements (e.g., emission limits and standards). Provided the source complies with the requirements, the Title V permit is renewed every 5 years to ensure that it contains any new requirements such as federal New Source Performance Standards or National Emission Standards for Hazardous Air Pollutants that have been established for the source category and there is sufficient monitoring, recording-keeping, and reporting requirements contained in the permit to assure compliance with the emission limits and standards.

The PSD permit for the PGE Coyote Springs plant was issued in 1994 and, until recently, there have not been any changes to the plant that would require another PSD permit. PGE recently submitted an application for a PSD permit for modifications to Unit 2. The PSD permit is being processed separately, but once it is issued, the requirements will be incorporated into the Title V permit. The PSD permit DEQ is currently processing is only required for greenhouse gases and not any other regulated pollutants because the other pollutant emissions will not increase as a result of the modification. PGE is not allowed to make the proposed changes to Unit 2 until the PSD permit is issued. PGE must continue to comply with the terms and conditions of the Title V permit until the PSD permit is issued and the requirements are incorporated into the permit.

Response to specific comments:

I. Impacts on the Columbia River Gorge National Scenic Area (CRGNSA)

The initial PSD permit issued for the PGE Coyote Springs Plant evaluated the impacts the source would have on visibility and deposition in Class I Wilderness Areas and National Parks. In addition, although not required, DEQ also evaluated the impacts on the Columbia River Gorge National Scenic Area. The federal land managers for the US Forest Service and National Parks were consulted for their input on the Class I area impact analysis during the initial permit action.

II. Columbia River Gorge National Scenic Act

Revisions to the CRGNSA Management Plan and *Columbia River Gorge Air Study and Strategy* do not require DEQ to conduct further analysis of existing sources as part of their Title V permit renewals. However, DEQ anticipates that many existing sources will be evaluated within the next 5 to 10 years under the "reasonable further progress" provisions of the national regional haze program required by 40 CFR 51.308. Until that evaluation is completed, it is difficult to say what sources, if any, would be required to conduct an analysis of the impacts on Class I areas.

III. DEQ's Air Quality Program and Coordination with EFSC

The regulation cited [OAR 340-202-0050(2)] applies to "new sources or expansions of existing sources". PGE is not proposing an "expansion of the existing source" for the Title V permit renewal. As stated above, the source's impacts were initially evaluated when the PSD permit was issued. The Title V permit incorporates the requirements of the PSD permit, so a separate analysis is not required when the Title V permit is issued. In addition, the EFSC requirement for evaluating "significant adverse impact" as it applies to DEQ's permitting program was satisfied when the PSD permit was issued pursuant to DEQ's rules for implementation of the federally mandated PSD program.

[8] OAR 340, Division 218

IV. Climate Change Impacts

Although not applicable to the Title V permit renewal, you should be aware that there are no provisions under the PSD program to evaluate "potential significant impacts on climate change". Since EPA has not established a National Ambient Air Quality Standard for greenhouse gases, the PSD program (when applicable) would be limited to determining the Best Available Control Technology (BACT) for greenhouse gases. The separate PSD permit action for Unit 2 mentioned above will address BACT for greenhouse gases, but it is not a requirement for the Title V permit renewal.

Although the air quality analysis you have requested are not requirements for Title V permit renewals, DEQ believes that the combined PSD and Title V permit programs are effective tools for helping to protect and enhance the air quality in the CRGNSA. The PSD program evaluates the impacts of new or modified sources and establishes requirements that are incorporated into Title V permits to ensure that the sources continue to comply with the requirements. In addition, when impacts from new or modified sources are above a significant level, a cumulative impact analysis is performed that includes all contributing sources.

Sincerely,

Mark Fisher
Senior Permit Writer
DEQ Eastern Region -Air Quality Section
(541) 633-2022

COMMENT 2:

From: Shawn Dolan
Sent: Thursday, April 25, 2013 8:05 AM
To: SWOFFORD Nancy
Cc: 'TALLANT'; 'Allison Dolan'
Subject: PGE Coyote Springs Title V

Comment regarding subject permit.

In reviewing the permit application, I do not see how compliance with visible emission limits is monitored and/or enforced. Visible emissions are the largest driver of public complaints and while restrictions on individual contaminant levels, e.g. PM Fine <= 48 ton/yr seems like a good limit. The public has very little understanding of what that looks like on a day to day basis.

Public concern related to air quality is higher now than it has ever been, and increasing exponentially given the increased rates of respiratory ailments and other undesirable health problems. Further, the visibility impairment in an area, that derives much of its economic base from tourism, should not be taken lightly.

Comment: the subject permit should include the use of US EPA Alternative Method 082, such that photographic evidence of visible emission limit compliance is available to the public, regulators and facility staff. Further, photographic evidence will assist researchers in the evolution and validation of the models used to determine visibility impairment in the region.

Thank you
Shawn Dolan
President
Virtual Technology LLC

RESPONSE 2:

From: Fisher Mark
Sent: Friday, May 17, 2013 9:47 AM
To: Shawn Dolan
Subject: PGE Coyote Springs Title V

Hello Shawn,

Thanks for the comments on the PGE Coyote Springs permit renewal and the information about Alternative Method 082. We will keep this in mind for sources that are expected to have visible emissions and could exceed the opacity limits. However, the combustion turbines and auxiliary boiler at the Coyote Springs plant burn only natural gas and our experience is that visible emissions do not occur when burning natural gas. Unit 1 at the plant does have the capability of burning distillate oil as a backup to natural gas and the permit requires visible emissions monitoring using EPA Method 9 when oil is burned in the turbine, but that has not happened in the past and is not expected to happen in the future.

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