

**OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY  
OREGON TITLE V OPERATING PERMIT AND ACID RAIN PERMIT  
SIGNIFICANT PERMIT MODIFICATION**

Eastern Region  
475 NE Bellevue Dr., Suite 110  
Bend, OR 97701  
Telephone (541) 388-6146

Issued in accordance with the provisions of ORS 468A.040  
and based on the land use compatibility findings included in the permit record.

**ISSUED TO:**

Portland General Electric Company  
121 SW Salmon Street  
Portland, OR 97204

**INFORMATION RELIED UPON:**

Application Number: 23913  
Received: 12/16/09

**PLANT SITE LOCATION:**

Coyote Springs Plant  
200 Ullman Blvd.  
Boardman, OR 97818

**LAND USE COMPATIBILITY STATEMENT:**

Issued by: City of Boardman  
Dated: 09/05/91

**ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY**

  
Linda Hayes-Gorman,  
Eastern Region Air Quality Manager

**MAY 13 2010**  
Date

Nature of Business: Electric Power Generation – natural gas or distillate fired, 25 MW or more  
Standard Industrial Code (SIC): 4911  
Acid Rain Program Identification: Plant Name: Coyote Springs  
State: Oregon  
ORIS code: 07350  
NADB#: CTG1 and CTG2

RESPONSIBLE OFFICIAL		ACID RAIN DESIGNATED REPRESENTATIVE		FACILITY CONTACT PERSON	
Title:	Plant Manager	Name:	Ray Hendricks	Name:	Ray Hendricks
		Title:	Designated Representative	Title:	Environmental Engineer
				Phone:	(541) 464-8519

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## LIST OF ABBREVIATIONS THAT MAY BE USED IN THIS PERMIT

ACDP	Air Contaminant Discharge Permit	NO <sub>x</sub>	Nitrogen oxides
Act	Federal Clean Air Act	O <sub>2</sub>	Oxygen
ASTM	American Society of Testing and Materials	OAR	Oregon Administrative Rules
Btu	British thermal unit	ODEQ	Oregon Department of Environmental Quality
CFR	Code of Federal Regulations	ORIS	Office of Regulatory Information Systems (Department of Energy)
CO	Carbon Monoxide	ORS	Oregon Revised Statutes
CPMS	Continuous parameter monitoring system	O&M	Operation and maintenance
DEQ	Department of Environmental Quality	Pb	Lead
dscf	Dry standard cubic feet	PCD	Pollution Control Device
EF	Emission factor	PM	Particulate matter
EPA	US Environmental Protection Agency	PM <sub>10</sub>	Particulate matter less than 10 microns in size
EU	Emissions Unit	ppm	Parts per million
FCAA	Federal Clean Air Act	PSEL	Plant Site Emission Limit
FSA	Fuel sampling and analysis	psia	pounds per square inch, actual
gr/dscf	Grain per dry standard cubic feet (1 pound = 7000 grains)	SERP	Source emissions reduction plan
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040	SIC	Standard Industrial Code
HCFC	Halogenated Chloro-Fluoro-Carbons	SO <sub>2</sub>	Sulfur dioxide
ID	Identification number	ST	Source test
I&M	Inspection and maintenance	VE	Visible emissions
NADB	National allowance data base	VMT	Vehicle miles traveled
NA	Not applicable	VOC	Volatile organic compounds

## PERMITTED ACTIVITIES

1. Until such time as this permit expires or is modified or revoked, the permittee is allowed to discharge air contaminants from those processes and activities directly related to or associated with air contaminant source(s) in accordance with the requirements, limitations, and conditions of this permit. [OAR 340-218-0010 and 340-218-0120(2)]
2. All conditions in this permit are federally enforceable, meaning that they are enforceable by DEQ, EPA, and citizens under the Clean Air Act, except as specified below: [OAR 340-218-0060 and 340-218-0070]
  - 2.a. Conditions 5, 6, 30, G5, and G9 (OAR 340-248-0005 through 340-248-0180) are only enforceable by the state.
  - 2.b. Attachment 1 of this permit provides a cross-reference for SIP rules that have been renumbered in the current Oregon Administrative Rules.

## EMISSIONS UNIT (EU) AND POLLUTION CONTROL DEVICE (PCD) IDENTIFICATION

3. The emissions units regulated by this permit are the following [OAR 340-218-0040(3)]:

Emission Unit Description	EU ID	Pollution Control Device Description	PCD ID
Combustion turbine 1	CT1.EU	SCR	SCR.CD1
Combustion turbine 2	CT2.EU	SCR	SCR.CD2
Auxiliary boiler	AB.EU	none	NA
Aggregate insignificant activities including the natural gas pipeline heater	AI.EU	none	NA

## EMISSION LIMITS AND STANDARDS

The following tables and conditions contain the applicable requirements along with the testing, monitoring, and recordkeeping requirements for the emissions units to which those requirements apply.

**Table 1. Facility wide emission limits and standards**

Applicable Requirement	Condition Number	Pollutant/Parameter	Limit/Standard	Averaging Time	Testing Condition	Monitoring Condition
340-208-0210(2)	4	Fugitive emissions	minimize	NA	NA	30
340-208-0300	5	Nuisance	no nuisance	NA	NA	30
340-208-0450	6	PM >250 $\mu$	no fallout	NA	NA	30
40 CFR §60.11(d)	7	Operation and maintenance	Good pollution control practices	NA	NA	NA
40 CFR Part 68	8	Risk management	Risk management plan	NA	NA	8

4. The permittee must not allow or permit any materials to be handled, transported, or stored; or a building, its appurtenances, or a road to be used, constructed, altered, repaired or demolished; or any equipment to be operated, without taking reasonable precautions to prevent particulate matter from becoming airborne. [OAR 340-208-0210(2)]

5. The permittee must not cause or allow air contaminants from any source to cause a nuisance. Nuisance conditions will be verified by Department personnel. [OAR 340-208-0300]
6. The permittee must not cause or permit the emission of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person. The Department will verify that the deposition exists and will notify the permittee that the deposition must be controlled. [OAR 340-208-0450]
7. At all times, including periods of startup, shutdown, and malfunction, the permittee must, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. [40 CFR 60.11(d), 60.4333(a), and 60.12 incorporated by reference]
8. The permittee must comply with the risk management plan (RMP) submitted to EPA and all other applicable Part 68 requirements. The permittee must certify compliance with the requirements of Part 68 as part of the semi-annual compliance certification required by Condition 51. [40 CFR Part 68]

**Table 2. Emissions Units Specific Emission Limits and Standards**

EU ID	Applicable Requirement	Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirements	
					Method	Condition No.
CT1.EU, CT2.EU and AB.EU	1995 ACDP Condition 16	9	Operating modes	See condition for fuel restrictions	Recordkeeping	31
CT1.EU and CT2.EU	340-208-0110(2)	10	Visible emissions	20% opacity, 3 min. in 60 min.	VE observations while burning oil; Fuel recordkeeping while burning natural gas	32
	340-226-0210(1)(b)	11.a	PM/PM <sub>10</sub>	0.1 gr/dscf	Periodic ST and VE observations while burning oil; Fuel recordkeeping while burning natural gas	31 and 32
	1995 ACDP Condition 3	11.b	PM/PM <sub>10</sub> natural gas	4.5 lbs/hr/unit	Fuel recordkeeping	31
	1995 ACDP Condition 4	13.a	NO <sub>x</sub> /natural gas	4.5 ppm at 15% O <sub>2</sub>	CEMS	36
	1995 ACDP Condition 4	13.a	NO <sub>x</sub> /natural gas	30 lbs/hr/unit	CEMS	36
	1995 ACDP Condition 5	15.a	CO/natural gas	15 ppm at 15% O <sub>2</sub>	CEMS	38
	1995 ACDP Condition 5	15.a	CO/natural gas	51 lbs/hr/unit	CEMS	38

EU ID	Applicable Requirement	Condition Number	Pollutant/Parameter	Limit/Standard	Monitoring Requirements	
					Method	Condition No.
CT1.EU	1995 ACDP Condition 3	11.c	PM/PM <sub>10</sub> /fuel oil	33 lb/hr	Periodic ST and VE observations	24 and 32
	340-228-0100	12	Distillate oil sulfur content	0.5% by weight	NA	34
	1995 ACDP Condition 4	13.b	NO <sub>x</sub> /fuel oil	15 ppm at 15% O <sub>2</sub>	CEMS	36
	1995 ACDP Condition 4	13.b	NO <sub>x</sub> /fuel oil	113 lbs/hr/unit	CEMS	36
	40 CFR 60.332(a)(1)	14.a	NO <sub>x</sub>	100 ppm at 15% O <sub>2</sub>	CEMS	36
	1995 ACDP Condition 5	15.b	CO/#2 fuel oil	20 ppm at 15% O <sub>2</sub>	CEMS	38
	1995 ACDP Condition 5	15.b	CO/#2 fuel oil	69 lbs/hr/unit	CEMS	38
	40 CFR 60.333(b)	1	Fuel sulfur content	0.8% by weight	Recordkeeping	34 and 39
CT2.EU	40 CFR 60.4320(a)	14.b	NO <sub>x</sub>	15 ppm or 0.43 lb/MWh	CEMS	36
	40 CFR 60.4330(a)(2)	14.d	SO <sub>2</sub>	0.060 lb/MMBtu heat input	Recordkeeping	40
AB.EU	340-208-0110(2) and (3)(a)	10	Visible emissions	20% opacity, 3 min. in 60 minutes	Fuel recordkeeping	31
	340-228-0210(1)(b)	17	PM/PM <sub>10</sub>	0.1 gr/dscf @ 50% excess air	Fuel recordkeeping	31
	40 CFR 60.42(a)(1)	18	PM	0.10 lb/mmBtu	Fuel recordkeeping	31
	40 CFR 60.42(a)(2)	16	Visible emissions	20% opacity, 6 min. avg.	Fuel recordkeeping	31
	40 CFR 60.44(a)(1) and 60.44b(a)(1)	19	NO <sub>x</sub>	0.20 lb/mmBtu	Recordkeeping or CEMS	40

9. The permittee must only operate the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU) as follows: [1995 ACDP Condition 16]
- 9.a. The permittee must only burn natural gas or ASTM #2 fuel oil in combustion turbine 1 (CT1.EU).
  - 9.b. The permittee must only burn natural gas in combustion turbine 2 (CT2.EU).
  - 9.c. The permittee must only burn natural gas in the auxiliary boiler (AB.EU).
10. The permittee must not cause or allow the emissions of any air contaminant into the atmosphere from the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU), for a period or periods aggregating more than three minutes in any one hour which is equal to or greater than 20% opacity, excluding uncombined water. [OAR 340-208-0110(2) and 340-208-0110(3)(a)]

The permittee is not required to monitor visible emissions from the combustion turbines (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU) while burning natural gas. The permittee is required to monitor visible emissions from combustion turbine CT1.EU while burning fuel oil in accordance with Condition 32. [See also Condition 26.]

11. The permittee must not cause or allow the emission of particulate matter from the combustion turbines (CT1.EU and CT2.EU) in excess of:
  - 11.a. For each combustion turbine (CT1.EU and CT2.EU), 0.1 grains per dry standard cubic feet [OAR 340-226-0210(1)(b)]; and
  - 11.b. For each combustion turbine (CT1.EU and CT2.EU), 4.5 pounds per hour while burning natural gas [1995 ACDP Condition 3]; and
  - 11.c. For combustion turbine 1 (CT1.EU), 33 pounds per hour while burning ASTM #2 fuel oil. [1995 ACDP Condition 3]

Particulate matter emissions are measured in accordance with Condition 24 and monitored in accordance with Condition 32.

12. The permittee must not use any ASTM Grade 2 distillate oil containing more than 0.5 percent sulfur by weight. [OAR 340-228-0110(2)]
13. The permittee shall not cause or allow the emission of nitrogen oxides from the combustion turbines (CT1.EU and CT2.EU) in excess of:
  - 13.a. For each combustion turbine (CT1.EU and CT2.EU), 4.5 ppm corrected to 15% oxygen and 30 pounds per hour as a 24-hour rolling average while burning natural gas; or
  - 13.b. For combustion turbine 1 (CT1.EU), 15 ppm corrected to 15% oxygen and 113 pounds per hour as a 24-hour rolling average while burning ASTM #2 fuel oil.

These limits do not apply during startup and shutdown if Department approved procedures are followed for the startup and shutdown. Nitrogen oxide emissions must be measured in accordance with Condition 36. [1995 ACDP Condition 4]

14. New Source Performance Standards (NSP) for the combustion turbines are as follows:
  - 14.a. The permittee must not cause to be discharged into the atmosphere from combustion turbine 1 (CT1.EU) any gases which contain nitrogen oxides in excess of 100 ppm corrected to 15% oxygen in accordance with 40 CFR 60.332(a)(1). Emissions in excess of 100 ppm during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c). However, for purposes of the excess emissions reports required in 40 CFR 60.7(c), an hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average  $\text{NO}_x$  concentration exceeds 100 ppm in accordance with 40 CFR 60.334 (j)(1)(iii). Nitrogen oxides emissions must be measured in accordance with Condition 36.
  - 14.b. The permittee must not cause to be discharged into the atmosphere from combustion turbine 2 (CT2.EU) any gases that contain nitrogen oxides (expressed as  $\text{NO}_2$ ) in excess of 15 ppm corrected to 15% oxygen or 0.43lbs/MWh, whichever is greater, in accordance with 40 CFR 60.4320(a). Emissions in excess of 15 ppm during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c). However, for purposes of excess emission reports required by 40 CFR 60.7(c), an excess emission is any 30 unit operating day rolling average for all periods of unit operation, including start-up, shutdown, and malfunction in accordance with 40 CFR 60.4350(h) and 60.4375(a). Nitrogen oxides emissions must be measured in accordance with Condition 36.

- 14.c. The sulfur content of any fuel burned in the combustion turbine 1 (CT1.EU) must not exceed 0.8% by weight. [40 CFR 60.333(b)] When burning natural gas, the permittee must use only pipeline grade natural gas. The sulfur content of the fuels must be measured in accordance with Condition 34 for fuel oil and Condition 39 for natural gas.
- 14.d. The permittee must not cause to be discharged into the atmosphere from combustion turbine 2 (CT2.EU) any gases that contain sulfur dioxide in excess of 0.060 lb/MMBtu-heat input in accordance with 40 CFR 60.4330(a)(2). The sulfur content of the fuels must be measured in accordance with Condition 39.
15. The permittee must not cause or allow the emission of carbon monoxide from the combustion turbines (CT1.EU and CT2.EU) in excess of:
- 15.a. For each combustion turbine (CT1.EU and CT2.EU), 15 ppm corrected to 15% oxygen and 51 pounds per hour as an 8-hour rolling average while burning natural gas; or
- 15.b. For combustion turbine 1 (CT1.EU), 20 ppm corrected to 15% oxygen and 69 pounds per hour as an 8-hour rolling average while burning ASTM #2 fuel oil.

These limits do not apply during startup and shutdown if Department approved procedures are followed for the startup and shutdown. Carbon monoxide emissions must be measured in accordance with Condition 38. [1995 ACDP Condition 5]

16. The permittee must not cause to be discharged into the atmosphere from the auxiliary boiler (AB.EU) any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity in accordance with 40 CFR 60.42(a)(2). Emissions in excess of 20 percent opacity during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c).

The permittee is not required to monitor visible emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]

17. The permittee must not cause or allow the emission of particulate matter from the auxiliary boiler (AB.EU) in excess of 0.1 grains per dry standard cubic feet, corrected to 50% excess air. [OAR 340-228-0210(1)(b)]

The permittee is not required to monitor particulate matter emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]

18. The permittee must not cause or allow the emission of particulate matter from the auxiliary boiler (AB.EU) in excess of 0.10 pounds per million Btu heat input. [40 CFR 60.42(a)(1)] Emissions in excess of 0.10 pound per million Btu heat input during periods of startup, shutdown, and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c).

The permittee is not required to monitor visible emissions from the auxiliary boiler (AB.EU) while burning natural gas. [See also Condition 26.]

19. The permittee must not discharge any gases from the auxiliary boiler (AB.EU) which contain nitrogen oxides in excess of 0.20 pound per million Btu heat input based on a 30-day rolling average. [40 CFR 60.44(a)(1) and 60.44b(a)(1). Nitrogen oxide emissions are measured in accordance with Condition 40.

### **Insignificant Activities Emission Limits and Standards**

20. The Department acknowledges that insignificant emissions units (IEUs) identified by rule as either categorically insignificant activities or aggregate insignificant emissions as defined in OAR 340-200-0020 exist at facilities required to obtain an Oregon Title V Operating Permit. IEUs must comply with all

applicable requirements. In general, the requirements that could apply to IEUs are incorporated as follows:

- 20.a. OAR 340-208-0110 (20% opacity)
- 20.b. OAR 340-226-0210 (0.1 gr/dscf for non-fugitive, non-fuel burning equipment)
- 20.c. OAR 340-226-0310 (process weight limit for non-fugitive, non-fuel burning process equipment)
- 20.d. OAR 340-228-0210 (0.1 gr/dscf corrected to 12% CO<sub>2</sub> or 50% excess air for fuel burning equipment)

Unless otherwise specified in this permit or an applicable requirement, the Department is not requiring any testing, monitoring, recordkeeping, or reporting for the particulate matter and visible emissions limits and standards that apply to insignificant emission units, including categorically insignificant activities and aggregate insignificant emissions. However, if testing were performed for compliance purposes, the permittee would be required to use the test methods identified in the definitions of “opacity” and “particulate matter” in OAR 340-208-0010 and perform the testing in accordance with the Department’s Source Sampling Manual.

#### PLANT SITE EMISSION LIMITS

21. The plant site emissions must not exceed the following limits for each 12 consecutive month period: [OAR 340-222-0040 through OAR 340-222-0043]

Pollutant	Annual PSEL (tons/yr)	Monitoring Requirements	
		Method	Condition Number
PM/ PM <sub>10</sub>	48	Recordkeeping	41
CO	452	CEM and recordkeeping	41
NO <sub>x</sub>	287	CEM and recordkeeping	41
SO <sub>2</sub>	39	FSA	41
VOC	39	Recordkeeping	41

#### EMISSION FEES

22. Emission fees will be based on the Plant Site Emissions Limits, unless the permittee elects to report actual emissions for one or more permitted processes/pollutants. If the permittee reports actual emissions for one or more permitted processes/pollutants, the permitted emissions for the remaining permitted processes/pollutants will be based on the following table: [OAR 340-220-0090]

Emission Source Description	ES/Process Code [DEQ]	PM <sub>10</sub>	SO <sub>2</sub>	NO <sub>x</sub>	VOC
Combustion turbine 1 (gas)	PS-1/P-1	18.3	4.7	123	6.1
Combustion turbine 1 (oil)	PS-1/P-2	9.9	29.7	33.5	0.9
Combustion turbine 2 (gas)	PS-2/P-1	19.7	5	131	6.5
Auxiliary boiler	PS-3/P-1	17.1	1.9	147	12.8
Aggregate insignificant emissions	FS-1/P-1	1	1	1	1

## TESTING REQUIREMENTS

The testing conditions in this section are based on OAR 340-212-0120 and 340-218-0050(3)(a); unless otherwise specified.

23. Unless otherwise specified in this permit, the permittee must conduct all testing in accordance with the Department's Source Sampling Manual and 40 CFR 60.8, where applicable.
  - 23.a. Only regular operating staff may adjust the processes or emission control device parameters during a compliance source test and within two (2) hours prior to the tests. Any operating adjustments made during a compliance source test, which are a result of consultation during the tests with source testing personnel, equipment vendors, or consultants, may render the source test invalid.
  - 23.b. Unless otherwise specified by permit condition or a Department approved source test plan, all compliance source tests must be performed at maximum operating rates (90 to 110% of device capacity).
  - 23.c. Each source test must consist of at least three (3) test runs and the emissions results must be reported as the arithmetic average of all valid test runs.
24. EPA Methods 1 through 4 and ODEQ Method 5 must be used for measuring particulate matter emissions from combustion turbine 1 (CT1.EU) while burning fuel oil.
  - 24.a. Testing is only required if fuel oil is burned in the combustion turbine for more than 438 hours in a calendar year. The test must be performed within six months following the date on which the fuel oil usage exceeds 438 hours in a calendar year.
  - 24.b. Each test run must be a minimum of 60 minutes long with a minimum sample volume of 45 dscf. The filter temperature of the sample train must be maintained at  $320 \pm 25$  °F. Following each test run, the sample train must be purged with clean air for at least 30 minutes at the average sample rate during the test run.
  - 24.c. Test results must be reported as grains per dry standard cubic feet (gr/dscf) and pounds per hour.
  - 24.d. During each test run, the permittee must record the following information:
    - 24.d.i. Visible emissions as measured by EPA Method 9 for a minimum period of six minutes either during the particulate emissions test or within 30 minutes before or after the particulate emissions test;
    - 24.d.ii. Combustion turbine load and gross electric output (MWge); and
    - 24.d.iii. As fired fuel feed rate (gallons/hr).
25. The permittee must conduct initial and subsequent performance tests for demonstrating compliance with conditions 14.b and 14.d in accordance with condition 25.a or 25.b, and 25.c, as follows:
  - 25.a. The permittee must conduct an initial performance test, as required in 40 CFR 60.8. Subsequent NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). [40 CFR 60.4400]
    - 25.a.i. There are two general methodologies that the permittee may use to conduct the performance tests. For each test run:
      - 25.a.i.A. Measure the NO<sub>x</sub> concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of 40 CFR Part 60. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO<sub>x</sub> emission rate:

- Where:
- E =  $1.194 \times 10^{-7} * (\text{NO}_x)_c * Q_{\text{std}}/P$
- E =  $\text{NO}_x$  emission rate, in lb/MWh
- $1.194 \times 10^{-7}$  = conversion constant, in lb/dscf-ppm
- $(\text{NO}_x)_c$  = average  $\text{NO}_x$  concentration for the run, in ppm
- $Q_{\text{std}}$  = stack gas volumetric flow rate, in dscf/hr
- P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR 60.4350(f)(2); or
- 25.a.i.B. Measure the  $\text{NO}_x$  and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of 40 CFR Part 60. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of 40 CFR Part 60 to calculate the  $\text{NO}_x$  emission rate in lb/MMBtu. Then, use the equation in condition 36.c to calculate the emissions in lb/MWh.
- 25.a.ii. Sampling traverse points for  $\text{NO}_x$  and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.
- 25.a.iii. Notwithstanding condition 25.a.ii, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:
- 25.a.iii.A. You may perform a stratification test for  $\text{NO}_x$  and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) of appendix A of 40 CFR Part 75.
- 25.a.iii.B. Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:
- 25.a.iii.B.1 If each of the individual traverse point  $\text{NO}_x$  concentrations is within  $\pm 10$  percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 5ppm or  $\pm 0.5$  percent  $\text{CO}_2$  (or  $\text{O}_2$ ) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average  $\text{NO}_x$  concentration during the stratification test; or
- 25.a.iii.B.2 For turbines with a  $\text{NO}_x$  standard less than or equal to 15 ppm @ 15%  $\text{O}_2$ , you may sample at a single

- point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or 0.15 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points.
- 25.a.iv. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.
- 25.a.iv.A. For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO<sub>x</sub> emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.
- 25.a.iv.B. Compliance with the applicable emission limit in condition 14.b must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO<sub>x</sub> emission rate at each tested level meets the applicable emission limit in condition 14.b
- 25.a.iv.C. If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in condition 25.b) as part of the initial performance test of the affected unit.
- 25.a.iv.D. The ambient temperature must be greater than 0°F during the performance test.
- 25.b. For NO<sub>x</sub>, the initial performance test required under 40 CFR 60.8 may be performed in the following manner: [40 CFR 60.4405]
- 25.b.i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.
- 25.b.ii. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
- 25.b.iii. Use the test data both to demonstrate compliance with the applicable NO<sub>x</sub> emissions unit and to provide the required reference method data for the RATA of the CEMS.
- 25.b.iv. Compliance with the applicable emission limit is achieved if the arithmetic average of all of the NO<sub>x</sub> emissions rates for the RATA runs, expressed in units of ppm and lb/MWh, does not exceed the emission limit.
- 25.c. For SO<sub>2</sub>, the permittee must conduct an initial performance test, as required in 40 CFR 60.8. Subsequent SO<sub>2</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Each performance test must be conducted as follows: [40 CFR 60.4415]
- 25.c.i. Collect a representative fuel sample following ASTM D5287 (incorporated by reference).
- 25.c.ii. Analyze the sample for the total sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processor Association Standard 2377, all of which are incorporated by reference.
- 25.c.iii. The fuel analyses of this condition may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency.

26. Unless otherwise specified in this permit or an applicable requirement, the Department is not requiring any testing, monitoring, recordkeeping, or reporting for the particulate matter and visible emissions limits and standards that apply to emissions units CT1.EU, CT2.EU, and AB.EU while burning natural gas. However, if testing were performed for compliance purposes, the permittee would be required to use the test methods identified in the definitions of “opacity” and “particulate matter” in OAR 340-208-0010 and perform the testing in accordance with the Department’s Source Sampling Manual.

## MONITORING REQUIREMENTS

The monitoring conditions in this section are based on OAR 340-218-0050(3)(a); unless otherwise specified.

### General Monitoring Requirements

27. The permittee must not knowingly render inaccurate any required monitoring device or method. [OAR 340-218-0050(3)(a)(E)]
28. Methods used to determine actual emissions for fee purposes must also be used for compliance determination and can be no less rigorous than the requirements of OAR 340-218-0080. [OAR 340-218-0050(3)(a)(F)]
29. Monitoring requirements must commence on the date of permit issuance unless otherwise specified in the permit or an applicable requirement. [OAR 340-218-0050(3)(a)(G)]

### Facility-wide Emissions Limits and Standards Monitoring

30. The permittee must maintain a log recording all written complaints or complaints received via telephone by the responsible official or a designated appointee that specifically refer to an air quality nuisance condition that may be caused by the permitted facility. The log must include the date of contact, time of observed nuisance condition, description of nuisance condition, location of receptor, status of plant operation during the observed period, and time of response to complainant. The permittee must investigate, make a determination as to the validity of the complaint, and resolve the problem, if possible, within two working days of receiving the complaint.

### Emissions Unit Specific Emissions Limits and Standards Monitoring

31. The permittee must monitor and record the type and amount of fuels used in each combustion turbine and boiler on an hourly basis.
32. Except when burning natural gas, the permittee must monitor visible emissions from combustion turbine 1 (CT1.EU) by conducting a modified EPA Method 22 test for a minimum period of six minutes. If, during the modified EPA Method 22, test visible emissions are detected for more than 5% of the observation period, the permittee must conduct a modified EPA Method 9 test within 24 hours. The modified EPA Method 9 test must be a minimum of 6 minutes long unless any one reading is greater than 20% opacity, then the observation period must be 60 minutes or until a violation of the applicable standard in Condition 10 is documented, whichever period is shorter. Each modified EPA Method 9 observation must represent 15 seconds for the purpose of determining the aggregate amount of time in a 60 minute period that the visible emissions are greater than 20% opacity.
- 32.a. The modified EPA Method 22 or 9 tests must be conducted daily while burning oil but not while the plant is in startup mode.
- 32.b. If 7 consecutive days of modified EPA Method 22 tests show no visible emissions or the modified EPA Method 9 test results are less than the applicable standard in Condition 10, the test frequency may be weekly.

- 32.c. If 4 consecutive weeks of modified EPA Method 22 tests show no visible emissions or the modified EPA Method 9 test results are less than the applicable standard in Condition 10, the test frequency may be monthly.
- 32.d. If 3 consecutive months of modified EPA Method 22 tests show no visible emissions or the modified EPA Method 9 test results are less than the applicable standard in Condition 10, the test frequency may be quarterly.
- 32.e. If 4 consecutive quarters of modified EPA Method 22 tests show no visible emissions or the modified EPA Method 9 test results are less than the applicable standard in Condition 10, the test frequency may be once every six months.
- 32.f. If any test result exceeds the standard in Condition 10, the permittee must take corrective action and the test frequency must be daily for 5 consecutive days following the exceedance. If the results of the daily tests are all less than the standard in Condition 10, the test frequency must be the same as before the exceedance occurred.
- 32.g. If, on a regularly scheduled test day, it is not possible to conduct a modified EPA Method 22 or 9 test due to inclement weather conditions or interference from other fugitive sources, the permittee must make three attempts during the day at approximately 10 a.m., noon, and 2 p.m. If it is still not possible to conduct the test, the permittee must perform the test the following day. The permittee must record in a log the reason for not conducting the test on a regularly scheduled test day.
- 32.h. Since it is unlikely that the visible emissions limits could be exceeded while burning natural gas, visible emissions monitoring is not required while burning natural gas. The permittee must record the type of fuel being burned in accordance with Condition 31.
33. The permittee must determine and record the heat input (million Btu/hr) to the combustion turbines for every hour or part of an hour any fuel is combusted following section 5 of procedure 5 in Appendix F of 40 CFR Part 75. [40 CFR 75.10(c)]
34. The permittee must monitor the sulfur content and gross calorific value of fuel oil burned in combustion turbine 1 (CT1.EU) in accordance with section 2.2 of procedure 2 of Appendix D to 40 CFR Part 75.
35. In accordance with 40 CFR 75.10(a)(1), 75.11(d)(2), and Appendix D of part 75, the permittee must install, certify, operate, maintain, and record the output of fuel flow meters for each type of fuel (ASTM #2 oil and natural gas) and calculate the sulfur dioxide emissions for each hour of operation as follows:
- 35.a. While burning distillate oil, convert the volumetric flow to mass flow using the density of the oil samples and calculate the SO<sub>2</sub> emissions using the following equation:

$$M_{SO_2} = 2.0 \times M_{oil} \times \%S_{oil}/100$$

Where,

$M_{SO_2}$	=	Hourly mass of SO <sub>2</sub> emitted from combustion of oil, lb/hr.
$M_{oil}$	=	Mass of oil consumed per hour, lb/hr.
$\%S_{oil}$	=	Percentage of sulfur by weight measured in the sample in accordance with Condition 34.
2.0	=	Ratio of lb SO <sub>2</sub> /lb S.

- 35.b. While burning natural gas, convert the volumetric flow to heat input using the heating value of the natural gas and calculate the SO<sub>2</sub> emissions using the following equation:

$$M_{SO_2g} = ER \times Hi_g$$

Where,

$M_{SO_2g}$	=	Hourly mass of SO <sub>2</sub> emissions from the combustion of pipeline natural gas, lb/hr.
ER	=	SO <sub>2</sub> emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

$HI_g$  = Hourly heat input of pipeline natural gas, calculated using procedures in appendix F of 40 CFR 75, in mmBtu/hr,  
 $HI_g = (Q_g \times GCV_g)/10000;$   
 Where:  $Q_g$  = fuel consumption in 100 scf/hr  
 $GCV_g$  = gross calorific value of natural gas fuel in Btu/scf provided by the natural gas supplier on a monthly basis.

36. The permittee must install, certify, operate, maintain, and record the output of a  $NO_x$  CEMS (consisting of a  $NO_x$  pollutant concentration monitor and an  $O_2$  diluent monitor) with automated DAHS for measuring and recording  $NO_x$  concentration (ppm) and emissions rates (lb/million Btu, lb/MWh, and lb/hr) discharged to the atmosphere in accordance with 40 CFR 75.10(a)(2) and 75.12. [40 CFR 60.334 and 60.4345]

36.a. The data acquisition and handling system must calculate and record the hourly  $NO_x$  emission rate in units of ppm and lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR Part 60. For any hour in which the hourly average  $O_2$  concentration exceeds 19.0 percent  $O_2$  (or the hourly  $CO_2$  concentration is less than 1.0 percent  $CO_2$ ), a diluents cap value of 19.0 percent  $O_2$  or 1.0 percent  $CO_2$  (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

36.b. The mass emissions rate in pounds per hour must be calculated as follows:

$M_{NO_x} = ER_{NO_x} \times HI_g$   
 Where,  
 $M_{NO_x}$  = Hourly mass of  $NO_x$  emissions from the combustion of pipeline natural gas, lb/hr.  
 $ER_{NO_x}$  =  $NO_x$  emission rate in lb/MMBtu as measured by the CEMS.  
 $HI_g$  = Hourly heat input of pipeline natural gas, calculated using procedures in appendix F of 40 CFR 75, in mmBtu/hr,  
 $HI_g = (Q_g \times GCV_g)/10000;$   
 where,  $Q_g$  = fuel consumption in 100 scf/hr  
 $GCV_g$  = gross calorific value of natural gas fuel in Btu/scf provided by the natural gas supplier on a monthly basis.

36.c. The mass emissions rate in pounds per megawatt hour from combustion turbine 2(CT2.EU) must be calculated as follows: [40 CFR 60.4350(f)]

$E = (NO_x)_h * (HI)_h / P$   
 Where,  
 $E$  = hourly  $NO_x$  emission rate, in lb/MWh  
 $(NO_x)_h$  = hourly  $NO_x$  emission rate, in lb/MMBtu  
 $(HI)_h$  = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flow monitor  
 $P$  = gross energy output of the stationary combustion turbine system in MW  
 $= (Pe)_t + (Pe)_c + Ps - Po$   
 $(Pe)_t$  = electrical or mechanical energy output of the combustion turbine in MW  
 $(Pe)_c$  = electrical or mechanical energy output (if any) of the steam turbine in MW  
 $Ps$  = useful thermal energy of the steam, measure relative to ISO conditions, not used to generate additional electric or mechanical output, in MW  
 $= Q * H / 3.414 \times 10^6$  Btu/MWh

- Q = measure steam flow rate in lb/hr
- H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and  $3.413 \times 10^6$  = conversion from Btu/h to MW.
- Po = other useful heat recovery, measure relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.
- 36.d. The permittee must ensure that all CEMS meet the equipment, installation, and performance specifications in 40 CFR Part 75 Appendix A. [40 CFR 75.10(b)]
- 36.e. The permittee must ensure that all CEMS are in operation at all times that each affected facility combusts any fuel and that the following requirements are met: [40 CFR 75.10(d)]
- 36.e.i. The permittee must ensure that each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The permittee must reduce all NO<sub>x</sub> concentration and NO<sub>x</sub> emissions rate data to 1-hour averages. The permittee must compute these averages from four or more data points equally spaced over each 1-hour period, except during periods when calibration, quality assurance, or maintenance activities pursuant to 40 CFR 75.21 and appendix B of 40 CFR Part 75 are being performed. During these periods, a valid hour must consist of at least two data points separated by a minimum of 15 minutes. For combined monitoring systems (NO<sub>x</sub> - diluent), the hourly average emission rate is valid only if the hourly average concentration from each of the component monitors is valid.
- 36.e.ii. Failure of an NO<sub>x</sub> CEMS to acquire the minimum number of data points comprising a valid hour, as specified in this condition, will result in the loss of such component data for the entire hour. The permittee must estimate and record emission or flow data for the missing hour by means of the automated DAHS, in accordance with 40 CFR Part 75 subpart D.
- 36.e.iii. Notwithstanding condition 36.e.ii, only quality assured data from the CEMS shall be used to identify excess emissions for the purposes of condition 14.b. Periods where missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under condition 53.b. [40 CFR 60.4350(d)]
- 36.f. The hourly average concentration of NO<sub>x</sub> in parts per million, corrected to 15% oxygen, and emission rates in lb/hr, lb/MMBtu-heat input, and lb/MWh, must be recorded at the end of each clock hour that the combustion turbines are operating.
- 36.g. For purposes of condition 13, the 24-hour rolling average concentration of NO<sub>x</sub> in parts per million, corrected to 15% oxygen, and emission rate in lb/hr must be calculated and recorded at the end of each clock hour (at the end of each clock hour, a new 24-hour average is calculated and recorded using the most recent hourly average and the previous twenty-three hourly averages). Emissions during periods of startup and shutdown are excluded from the 24-hour rolling average.
- 36.h. For the purposes of condition 14.a, a 4-hour rolling average NO<sub>x</sub> concentration is the arithmetic average of the average NO<sub>x</sub> concentration measured by the CEMS for a given hour (corrected to 15% O<sub>2</sub> and, if required under 40 CFR 60.335 (b)(1), to ISO standard conditions) and the three unit operating hour average NO<sub>x</sub> concentrations immediately preceding that unit operating hour. [40 CFR 60.334(j)(1)(iii)(A)]
- 36.i. For the purposes of condition 14.b, a 30-day rolling average NO<sub>x</sub> emissions is the arithmetic average of all hourly NO<sub>x</sub> emissions data in ppm or lb/MWh measured by the CEMS for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO<sub>x</sub> emissions rates for the preceding 30 unit operating days if a valid NO<sub>x</sub> emissions rate is obtained for at least 75 percent of all operating hours. [40 CFR 60.4380(h)]
- 36.j. The permittee must ensure that each CEMS and component thereof is capable of accurately measuring, recording, and reporting data, and must not incur a full scale exceedance. [40 CFR 75.10(f)]

- 36.k. Whenever the permittee makes a replacement, modification, or change in the certified CEMS, including the automated DAHS, that significantly affects the ability of the system to measure or record the NO<sub>x</sub> emission rate, the permittee must recertify the CEMS or component in accordance with 40 CFR 75.20(b).
- 36.l. The permittee must operate, calibrate, and maintain each CEMS used under the Acid Rain Program according to the quality assurance and quality control procedures in appendix B of 40 CFR Part 75. [40 CFR 75.10(b) and 75.21(a)]
- 36.m. The permittee must ensure that all calibration gases used to quality assure the operation of the instrumentation required by this permit must meet the definition in 40 CFR 72.2. [40 CFR 75.21(c)]
- 36.n. If an out-of-control period occurs to a monitor or CEMS, the permittee must take corrective action and repeat the tests applicable to the "out-of-control parameter" in accordance with 40 CFR 75.24.
- 36.o. Whenever a valid hour of NO<sub>x</sub> emissions rate data have not been measured and recorded, the permittee must provide substitute data in accordance with 40 CFR 75.30 through 75.33.
- 36.p. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions. [40 CFR 60.4345(d)]
- 36.q. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in this condition and Condition 37. For the CEMS and fuel flow meters, the permittee may satisfy the requirements of this condition by implementing the QA program and plan described in section 1 of appendix B to 40 CFR part 75. [40 CFR 60.4345(e)]
37. In accordance with 40 CFR 60.4345(c), 75.10(a)(3)(ii), 75.13(b), and appendix G of part 75, the permittee must install, certify, operate, maintain, and record the output of fuel flow meters for each type of fuel and calculate the carbon dioxide emissions for each day of operation as follows:

$$W_{CO_2} = (F_c \times H \times U_f \times MW_{CO_2}) / 2,000$$

Where,

W <sub>CO2</sub>	=	Daily mass of CO <sub>2</sub> emitted from combustion, tons/day
F <sub>c</sub>	=	Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1420 scf/mmBtu for distillate fuel oil
H	=	Daily heat input in mmBtu, as reported in company records
U <sub>f</sub>	=	1/385 scf CO <sub>2</sub> /lb-mole at 14.7 psia and 68°F
MW <sub>CO2</sub>	=	Molecular weight of carbon dioxide (44 lb/lbmole)

38. The permittee must install, calibrate, maintain, operate, and record the output of a continuous emissions monitoring system for measuring carbon monoxide emissions and diluent oxygen from the combustion turbines (s CT1.EU and CT2.EU): [1995 ACDP Condition 18 and 19.e]
- 38.a. The CEMS must, at a minimum, conform with the Department's Continuous Monitoring Manual dated January 1992.
- 38.b. Mass emissions of carbon monoxide must be recorded each clock hour that the combustion turbines are operating using the following equation:

$$M_{CO} = C_{CO} / 10^6 \times MW_{CO} / 385 \times F_d \times 20.9 / (20.9 - \%O_2) \times HI$$

Where,

M <sub>CO</sub>	=	Hourly mass of CO emissions, lb/hr
C <sub>CO</sub>	=	Hourly average CO concentration, ppm (uncorrected)
1/10 <sup>6</sup>	=	Conversion from ppm to a fraction
MW <sub>CO</sub>	=	Molecular weight of CO = 28 lb/lb-mole
385	=	Cry standard cubic feet per lb-mole at 14.7 psia and 68°F
F <sub>d</sub>	=	Dry fuel factor = 8710 dscf/mmBtu for natural gas and 9190 dscf/mmBtu for ASTM #2 distillate fuel oil

HI = Hourly heat input = cubic feet of natural gas or gallons of oil burned time the most recent heating value. (HI is in units of mmBtu/hr)

- 38.c. The concentration of CO in parts per million, corrected to 15% oxygen, and emissions rate in pounds per hour must be recorded each clock hour that the combustion turbines are operating as an hourly average and an 8-hour rolling average (at the end of each clock hour, a new eight hour average is calculated and recorded using the most recent hourly average and the previous seven hourly averages).
39. A customized fuel gas monitoring schedule for sulfur, as hydrogen sulfide, as approved by EPA on December 8, 1993, must be conducted as follows: [modified 1995 ACDP Condition 19.b and 40 CFR 60.334(h)(3)]
- 39.a. Sulfur fuel gas monitoring must be conducted semi-annually. Sampling must be conducted at the plant site, or as approved by the Department in advance.
- 39.b. Nitrogen monitoring is waived for pipeline quality natural gas, as there is no fuel-bound nitrogen and the free nitrogen does not contribute appreciably to NO<sub>x</sub> emissions.
- 39.c. The permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in combustion turbine 1 (CT1.EU) if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring.
- 39.d. The permittee must demonstrate compliance with Condition 14.d by providing a natural gas tariff sheet to the Department that verifies the natural gas burned in combustion turbine 2 (CT2.EU) contains a total sulfur content of 20 grains per 100 standard cubic feet, or less, in accordance with 40 CFR 60.4365(a). A copy of the tariff sheet must be maintained on site and be available for Department review upon request.
40. If the natural gas annual capacity factor for the auxiliary boiler (AB.EU) exceeds 10%, the permittee must monitor the NO<sub>x</sub> emissions in accordance with 40 CFR 60.48b(i). The permittee must record and maintain records of the amount of natural gas combusted during each day and calculate the annual capacity factor for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [40 CFR 60.49b(d)] The heat input that corresponds to 10% of the annual capacity factor for the auxiliary boiler (AB.EU) is 2.22x10<sup>5</sup> million Btu/year.

#### Plant Site Emissions Monitoring: [OAR 340-222-0080]

41. The permittee must determine compliance with the Plant Site Emission Limits established in Condition 21 of this permit by conducting monitoring and calculations for each 12-month period in accordance with the following procedures, test methods, and frequencies:
- 41.a. The permittee must calculate emissions using the following formula, process parameters, and emission factors:

$$E = P_{eu} \times EF_{eu} \times K$$

Where,

- E = Pollutant emissions in lbs/month and tons/yr.  
 P<sub>eu</sub> = Process parameter identified in the table below;  
 EF<sub>eu</sub> = Emission factor identified for each emissions unit and pollutant in table below;  
 K = Conversion constant: 1 lb/lb for daily and monthly emissions calculations; 1 ton/2,000 lbs for annual emissions calculations.

ES Description	Throughput Type [Units]	PM <sub>10</sub>	SO <sub>2</sub>	NO <sub>x</sub>	CO	VOC	PB
Combustion turbine 1	Natural Gas [MILLION CUBIC FEET]	2.5	MB	CEMS	CEMS	0.83	
Combustion turbine 1	Distillate Oil [1000 GALLONS]	2.42	MB	CEMS	CEMS	0.21	7.83E-03
Combustion turbine 2	Natural Gas [MILLION CUBIC FEET]	2.5	MB	CEMS	CEMS	0.83	
Auxiliary boiler	Natural Gas [MILLION CUBIC FEET]	5.62	0.64	48.4	39.8	4.2	
Aggregate insignificant emissions	Constant Time (fugitives) [YEAR]	2000	2000	2000	2000	2000	

- 41.b. The annual SO<sub>2</sub>, NO<sub>x</sub> and CO emissions for combustion turbines 1 and 2 are the sum of the hourly emissions measured in accordance with permit conditions 35, 36, and 38.
- 41.c. The annual plant site emissions for each pollutant are the sum of the emissions determined by conditions 41.a and 41.b.
- 41.d. The emissions factors listed in Condition 41.a are not enforceable limits unless otherwise specified in this permit. Compliance with PSELs must only be determined by the calculations contained in this Condition.

#### RECORDKEEPING REQUIREMENTS

The recordkeeping conditions in this section are based on OAR 340-218-0050(3)(b); unless otherwise specified.

##### General Recordkeeping Requirements

42. The permittee must maintain the following general records of testing and monitoring required by this permit: [OAR 340-218-0050(b)(A)]
- 42.a. The date, place as defined in the permit, and time of sampling or measurements;
- 42.b. The date(s) analyses were performed;
- 42.c. The company or entity that performed the analyses;
- 42.d. The analytical techniques or methods used;
- 42.e. The results of such analyses;
- 42.f. The operating conditions as existing at the time of sampling or measurement; and
- 42.g. The records of quality assurance for continuous monitoring systems (including but not limited to quality control activities, audits, calibration drift checks).
43. Unless otherwise specified by permit condition, the permittee must make every effort to maintain 100 percent of the records required by the permit. If information is not obtained or recorded for legitimate reasons (e.g., the monitor or data acquisition system malfunctions due to a power outage), the missing record(s) will not be considered a permit deviation provided the amount of data lost does not exceed 10% of the averaging periods in a reporting period or 10% of the total operating hours in a reporting period, if no averaging time is specified. Upon discovering that a required record is missing, the permittee must document the reason for the missing record. In addition, any missing record that can be recovered from other available information will not be considered a missing record. [340-212-0160, OAR 340-214-0110, and 340-218-0050(3)(b)]
44. Recordkeeping requirements must commence on the date of permit issuance unless otherwise specified in the permit or an applicable requirement. [OAR 340-218-0050(3)(b)(C)]

45. Unless otherwise specified, the permittee must retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. All existing records required by the previous Oregon Title V Operating Permit must also be retained for five (5) years from the date of the monitoring sample, measurement, report, or application. [OAR 340-218-0050(b)(B) and 40 CFR §60.7(f), where applicable]

#### Source Specific Recordkeeping Requirements

46. The permittee must maintain the following specific records of required monitoring:
- 46.a. Monthly and annual amount of natural gas burned in the combustion turbines and auxiliary boiler by unit;
  - 46.b. Monthly and annual amount of #2 fuel oil burned in combustion turbine 1 (CT1.EU);
  - 46.c. Sulfur content of the #2 fuel oil burned in combustion turbine 1 (CT1.EU) (% by weight);
  - 46.d. Sulfur content of the natural gas or records demonstrating that the natural gas meets the definition of natural gas in 40 CFR 60.331(u) and 60.4420;
  - 46.e. Heating value of the fuels;
  - 46.f. Combustion turbine visible emission observation reports, if oil is burned;
  - 46.g. Annual pollutant emissions for each 12 consecutive calendar month period;
  - 46.h. Occurrence and length of downtime for all pollution control devices;
  - 46.i. Excess emissions; and
  - 46.j. NSPS records for the combustion turbines and auxiliary boiler in accordance with 40 CFR 60.7(b) and (f), including:
    - 46.j.i. Occurrence and duration of any startup, shutdown, or malfunction in operation;
    - 46.j.ii. Any malfunction of the air pollution control equipment; or
    - 46.j.iii. Any periods during which a continuous monitoring system or monitoring device is inoperative.

#### REPORTING REQUIREMENTS

The reporting conditions in this section are based on OAR 340-218-0050(3)(c); unless otherwise specified.

#### General Reporting Requirements

47. Excess Emissions Reporting The permittee must report all excess emissions as follows: [OAR 340-214-0300 through 340-214-0360]
- 47.a. As soon as possible, but not later than 12 hours after the beginning of an excess emissions event, notify the Department of an excess emission event by phone, e-mail, or facsimile; and
  - 47.b. Within 15 days of the excess emissions event, submit a written report that contains the following information: [OAR 340-214-0340(1)]
    - 47.b.i. The date and time of the beginning of the excess emissions event and the duration or best estimate of the time until return to normal operation;
    - 47.b.ii. The date and time the owner or operator notified the Department of the event;
    - 47.b.iii. The equipment involved;
    - 47.b.iv. Whether the event occurred during planned startup, planned shutdown, scheduled maintenance, or as a result of a breakdown, malfunction, or emergency;
    - 47.b.v. Steps taken to mitigate emissions and corrective action taken, including whether the approved procedures for a planned startup, shutdown, or maintenance activity were followed;

- 47.b.vi. The magnitude and duration of each occurrence of excess emissions during the course of an event and the increase over normal rates or concentrations as determined by continuous monitoring or best estimate (supported by operating data and calculations);
- 47.b.vii. The final resolution of the cause of the excess emissions; and
- 47.b.viii. Where applicable, evidence supporting any claim that emissions in excess of technology-based limits were due to any emergency pursuant to OAR 340-214-0360.
- 47.c. In the event of any excess emissions which are of a nature that could endanger public health and occur during non-business hours, weekends, or holidays, the permittee must immediately notify the Department by calling the Oregon Accident Response System (OARs). The current number is 1-800-452-0311.
- 47.d. If startups, shutdowns, or scheduled maintenance may result in excess emissions, the permittee must submit startup, shutdown, or scheduled maintenance procedures used to minimize excess emissions to the Department for prior authorization, as required in OAR 340-214-0310 and 340-214-0320. New or modified procedures must be received by the Department in writing at least 72 hours prior to the first occurrence of the excess emission event. The permittee must abide by the approved procedures and have a copy available at all times.
- 47.e. The permittee must notify the Department of planned startup/shutdown or scheduled maintenance events.
- 47.f. The permittee must continue to maintain a log of all excess emissions in accordance with OAR 340-214-0340(3). However, the permittee is not required to submit the detailed log with the semi-annual and annual monitoring reports. The permittee is only required to submit a brief summary listing the date, time, and the affected emissions units for each excess emission that occurred during the reporting period. [OAR 340-218-0050(3)(c)]
48. Permit Deviations Reporting: The permittee must promptly report deviations from permit requirements that do not cause excess emissions, including those attributable to upset conditions, as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. "Prompt" means within fifteen (15) days of the deviation. Deviations that cause excess emissions, as specified in OAR 340-214-0300 through 340-214-0360 must be reported in accordance with OAR 340-214-0340. [OAR 340-218-0050(3)(c)(B)]
49. All required reports must be certified by a responsible official consistent with OAR 340-218-0040(5); [OAR 340-218-0050(3)(c)(D)]
50. Reporting requirements must commence on the date of permit issuance unless otherwise specified in the permit. [OAR 340-218-0050(3)(c)(E)]

Addresses of regulatory agencies are the following, unless otherwise instructed:

DEQ – Eastern Region	DEQ – Air Quality Division	Air Operating Permits
475 NE Bellevue Dr., Suite 110	811 SW Sixth Avenue	US Environmental Protection Agency
Bend, OR 97701	Portland, OR 97204	1200 Sixth Avenue, Suite 900
(541) 388-6146	(503) 229-5359	Seattle, WA 98101

### **Semi-annual and Annual Reports**

51. The permittee must submit three (3) copies of reports of any required monitoring at least every 6 months, completed on forms approved by the Department. Six month periods are January 1 to June 30, and July 1 to December 31. One copy of the report must be submitted to EPA and two copies to the DEQ regional office. All instances of deviations from permit requirements must be clearly identified in such reports: [OAR 340-218-0050(3)(c)(A) and 340-218-0080(6)(d)]

- 51.a. The first semi-annual report is due by July 30 and must include the semi-annual compliance certification. [OAR 340-218-0080].
- 51.b. The annual report is due by February 15 and must consist of the following:
- 51.b.i. Specific annual reporting requirements:
    - 51.b.i.A. Amount of fuel oil burned in combustion turbine 1 (CT1.EU) for the calendar year;
    - 51.b.i.B. Amount of natural gas burned in each combustion turbine (CT1.EU and CT2.EU) and in the auxiliary boiler (AB.EU) for the calendar year;
    - 51.b.i.C. Hours of operation for each combustion turbine (CT1.EU and CT2.EU) and auxiliary boiler (AB.EU);
    - 51.b.i.D. Greenhouse gas emissions report in accordance with OAR Chapter 340, Division 25; and
    - 51.b.i.E. Annual pollutant emissions from the entire facility for each 12 consecutive calendar month period during the calendar year.
  - 51.b.ii. The emission fee report; [OAR 340-220-0100]
  - 51.b.iii. A summary of the excess emissions upset log; and [OAR 340-214-0340]
  - 51.b.iv. The second semi-annual compliance certification for the period of July 1 through December 31. [OAR 340-218-0080]
52. The semi-annual compliance certification must include the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable): [OAR 340-218-0080(6)(c)]
- 52.a. The identification of each term or condition of the permit that is the basis of the certification;
  - 52.b. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means must include, at a minimum, the methods and means required under OAR 340-218-0050(3). *Note: Certification of compliance with the monitoring conditions in the permit is sufficient to meet this requirement, except when the permittee must certify compliance with new applicable requirements incorporated by reference into the permit. When certifying compliance with new applicable requirements that are incorporated by reference, the permittee must provide the information required by this condition.* If necessary, the owner or operator also must identify any other material information that must be included in the certification to comply with section 113(c)(2) of the FCAA, which prohibits knowingly making a false certification or omitting material information;
  - 52.c. The status of compliance with terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification must be based on the method or means designated in condition 52.b of this rule. The certification must identify each deviation and take it into account in the compliance certification. The certification must also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance, as defined under OAR 340-200-0010, occurred; and
  - 52.d. Such other facts as the Department may require to determine the compliance status of the source.
  - 52.e. Notwithstanding any other provision contained in any applicable requirement, the owner or operator may use monitoring as required under OAR 340-218-0050(3) and incorporated into the permit, in addition to any specified compliance methods, for the purpose of submitting compliance certifications. [OAR 340-218-0080(6)(e)]
53. Other reporting requirements include the following:
- 53.a. Source test plans;
  - 53.b. Two copies of semi-annual reports submitted to the Eastern Region of the Department and one copy submitted to the EPA that are postmarked by the 30th day following the end of each semi-

annual calendar period. The report must include a log of all planned and unplanned excess emissions and a monitoring system performance report in accordance with 40 CFR 60.7(c), 60.49b(i), 60.334(j), and 60.4375(b). The excess emission report must include the following information:

- 53.b.i. Magnitude of the excess emissions computed in accordance with 40 CFR 60.13(h), including any conversion factor used;
- 53.b.ii. The date and time of commencement and completion of each excess emission period;
- 53.b.iii. The amount of time each combustion turbine was operated during the reporting period;
- 53.b.iv. Identification of which periods of excess emissions occurred during startups, shutdowns, or malfunctions;
- 53.b.v. The nature and cause of any malfunction reported and the corrective actions or preventative measures taken;
- 53.b.vi. The date and time of periods when the continuous monitoring system is inoperative, except during periods of zero and span checks; and
- 53.b.vii. The excess emission reports required by Condition 53.b are only applicable to the following emissions units as follows:
  - 53.b.vii.A. combustion turbine 1 (CT1.EU) for conditions 14.a and 14.c;
  - 53.b.vii.B. combustion turbine 2 (CT2.EU) for conditions 14.b and 14.d; and
  - 53.b.vii.C. auxiliary boiler (AB.EU), if a NO<sub>x</sub> CEMS is required to be installed in accordance with Condition 40.
- 53.c. A quarterly report that includes the annual capacity factor for the auxiliary boiler (AB.EU) over the previous 12 months for each month in the calendar quarter. [40 CFR 60.49b(q)(1)] The report must be postmarked within 30 days following the last day of the calendar quarter. One copy of the report must be submitted to EPA and one copy to the Eastern Region office of the DEQ.
- 53.d. Notification at least 60 days prior to any physical or operational change which may increase the emission rate of any air pollutant to which a standard applies in accordance with 40 CFR 60.7(a)(4).

#### NON-APPLICABLE REQUIREMENTS

- 54. Non-applicable requirements:
  - 54.a. The NESHAP for stationary combustion turbines (40 CFR Part 63, subpart YYYY) is not applicable to this facility because it is not a major source of hazardous air pollutant emissions. Should this source become a major source of HAPs, subpart YYYY will be applicable. [OAR 340-218-0110]
  - 54.b. 40 CFR Part 60, subpart KKKK does not apply to combustion turbine 1 (CT1.EU) because the turbine was installed prior to the applicability date in the standard and the unit has not been modified. [40 CFR 60.14]  
40 CFR Part 60, subparts Db and GG do not apply to combustion turbine 2 (CT2.EU) because the turbine is subject to 40 CFR Part 60, subpart KKKK. [40 CFR 60.4305(b)]

## GENERAL CONDITIONS

G1. General Provision

Terms not otherwise defined in this permit have the meaning assigned to such terms in the referenced regulation.

G2. Reference materials

Where referenced in this permit, the versions of the following materials are effective as of the dates noted unless otherwise specified in this permit:

- a. Source Sampling Manual; January 23, 1992 - State Implementation Plan Volume 3, Appendix A4;
- b. Continuous Monitoring Manual; January 23, 1992 - State Implementation Plan Volume 3, Appendix A6; and
- c. All state and federal regulations as in effect on the date of issuance of this permit.

G3. Applicable Requirements [OAR 340-218-0010(3)(b)]

Oregon Title V Operating Permits do not replace requirements in Air Contaminant Discharge Permits (ACDP) issued to the source even if the ACDP(s) have expired. For a source operating under a Title V permit, requirements established in an earlier ACDP remain in effect notwithstanding expiration of the ACDP or Title V permit, unless a provision expires by its terms or unless a provision is modified or terminated following the procedures used to establish the requirement initially. Source specific requirements, including, but not limited to TACT, RACT, BACT, and LAER requirements, established in an ACDP must be incorporated into the Oregon Title V Operating Permit and any revisions to those requirements must follow the procedures used to establish the requirement initially.

G4. Compliance [OAR 340-218-0040(3)(n)(C), 340-218-0050(6), and 340-218-0080(4)]

- a. The permittee must comply with all conditions of this permit. Any permit condition noncompliance constitutes a violation of the Federal Clean Air Act and/or state rules and is grounds for enforcement action; for permit termination, revocation and re-issuance, or modification; or for denial of a permit renewal application. Any noncompliance with a permit condition specifically designated as enforceable only by the state constitutes a violation of state rules only and is grounds for enforcement action; for permit termination, revocation and re-issuance, or modification; or for denial of a permit renewal application.
- b. Any schedule of compliance for applicable requirements with which the source is not in compliance at the time of permit issuance is supplemental to, and does not sanction noncompliance with the applicable requirements on which it is based.
- c. For applicable requirements that will become effective during the permit term, the source must meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.

G5. Masking Emissions:

The permittee may not install or use any device or other means designed to mask the emission of an air contaminant that causes or is likely to cause detriment to health, safety, or welfare of any person or otherwise violate any other regulation or requirement. [OAR 340-208-0400] This condition is enforceable only by the State.

G6. Credible Evidence:

Notwithstanding any other provisions contained in any applicable requirement, any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of any such applicable requirements. [OAR 340-214-0120]

G7. Certification [OAR 340-214-0110, 340-218-0040(5), 340-218-0050(3)(c)(D), and 340-218-0080(2)]

Any document submitted to the Department or EPA pursuant to this permit must contain certification by a responsible official of truth, accuracy and completeness. All certifications must state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and, complete. The permittee must promptly, upon discovery, report to the Department a material error or omission in these records, reports, plans, or other documents.

G8. Open Burning [OAR Chapter 340, Division 264]

The permittee is prohibited from conducting open burning, except as may be allowed by OAR 340-264-0020 through 340-264-0200.

G9. Asbestos [40 CFR Part 61, Subpart M (federally enforceable), OAR Chapter 340-248-0005 through 340-248-0180 (state-only enforceable) and 340-248-0205 through 340-248-0280]

The permittee must comply with OAR Chapter 340, Division 248, and 40 CFR Part 61, Subpart M when conducting any renovation or demolition activities at the facility.

G10. Stratospheric Ozone and Climate Protection [40 CFR 82 Subpart F, OAR 340-260-0040]

The permittee must comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, Recycling and Emissions Reduction.

G11. Permit Shield [OAR 340-218-0110]

- a. Compliance with the conditions of the permit is deemed compliance with any applicable requirements as of the date of permit issuance provided that:
  - i. such applicable requirements are included and are specifically identified in the permit, or
  - ii. the Department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.
- b. Nothing in this rule or in any federal operating permit alters or affects the following:
  - i. the provisions of ORS 468.115 (enforcement in cases of emergency) and ORS 468.035 (function of department);
  - ii. the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
  - iii. the applicable requirements of the national acid rain program, consistent with section 408(a) of the FCAA; or
  - iv. the ability of the Department to obtain information from a source pursuant to ORS 468.095 (investigatory authority, entry on premises, status of records).
- c. Sources are not shielded from applicable requirements that are enacted during the permit term, unless such applicable requirements are incorporated into the permit by administrative amendment, as provided in OAR 340-218-0150(1)(h), significant permit modification, or reopening for cause by the Department.

G12. Inspection and Entry [OAR 340-218-0080(3)]

Upon presentation of credentials and other documents as may be required by law, the permittee must allow the Department of Environmental Quality, or an authorized representative (including an authorized contractor acting as a representative of the EPA Administrator), to perform the following:

- a. enter upon the permittee's premises where an Oregon Title V Operating Permit program source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

- b. have access to and copy, at reasonable times, any records that must be kept under conditions of the permit;
- c. inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- d. as authorized by the FCAA or state rules, sample or monitor, at reasonable times, substances or parameters, for the purposes of assuring compliance with the permit or applicable requirements.

G13. Fee Payment [OAR 340-220-0010, and 340-220-0030 through 340-220-0190]

The permittee must pay an annual base fee and an annual emission fee for particulates, sulfur dioxide, nitrogen oxides, and volatile organic compounds. The permittee must submit payment to the Department of Environmental Quality, Business Office, 811 SW 6th Avenue, Portland, OR 97204, within 30 days of the date the Department mails the fee invoice or August 1 of the year following the calendar year for which emission fees are paid, whichever is later. Disputes must be submitted in writing to the Department of Environmental Quality. Payment must be made regardless of the dispute. User-based fees will be charged for specific activities (e.g., computer modeling review, ambient monitoring review, etc.) requested by the permittee.

G14. Off-Permit Changes to the Source [OAR 340-218-0140(2)]

- a. The permittee must monitor for, and record, any off-permit change to the source that:
  - i. is not addressed or prohibited by the permit;
  - ii. is not a Title I modification;
  - iii. is not subject to any requirements under Title IV of the FCAA;
  - iv. meets all applicable requirements;
  - v. does not violate any existing permit term or condition; and
  - vi. may result in emissions of regulated air pollutants subject to an applicable requirement but not otherwise regulated under this permit or may result in insignificant changes as defined in OAR 340-200-0020.
- b. A contemporaneous notification, if required under OAR 340-218-0140(2)(b), must be submitted to the Department and the EPA.
- c. The permittee must keep a record describing off-permit changes made at the facility that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those off-permit changes.
- d. The permit shield of condition G11 does not extend to off-permit changes.

G15. Section 502(b)(10) Changes to the Source [OAR 340-218-0140(3)]

- a. The permittee must monitor for, and record, any section 502(b)(10) change to the source, which is defined as a change that would contravene an express permit term but would not:
  - i. violate an applicable requirement;
  - ii. contravene a federally enforceable permit term or condition that is a monitoring, recordkeeping, reporting, or compliance certification requirement; or
  - iii. be a Title I modification.
- b. A minimum 7-day advance notification must be submitted to the Department and the EPA in accordance with OAR 340-218-0140(3)(b).
- c. The permit shield of condition G11 does not extend to section 502(b)(10) changes.

G16. Administrative Amendment [OAR 340-218-0150]

Administrative amendments to this permit must be requested and granted in accordance with OAR 340-218-0150. The permittee must promptly submit an application for the following types of administrative amendments upon becoming aware of the need for one, but no later than 60 days of such event:

- a. legal change of the registered name of the company with the Corporations Division of the State of Oregon, or
- b. sale or exchange of the activity or facility.

G17. Minor Permit Modification [OAR 340-218-0170]

The permittee must submit an application for a minor permit modification in accordance with OAR 340-218-0170.

G18. Significant Permit Modification [OAR 340-218-0180]

The permittee must submit an application for a significant permit modification in accordance with OAR 340-218-0180

G19. Staying Permit Conditions [OAR 340-218-0050(6)(c)]

Notwithstanding conditions G17 and G18, the filing of a request by the permittee for a permit modification, revocation and re-issuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

G20. Construction/Operation Modification [OAR 340-218-0190]

The permittee must obtain approval from the Department prior to construction or modification of any stationary source or air pollution control equipment in accordance with OAR 340-210-0200 through OAR 340-210-0250.

G21. New Source Review Modification [OAR 340-224-0010]

The permittee may not begin construction of a major source or a major modification of any stationary source without having received an air contaminant discharge permit (ACDP) from the Department and having satisfied the requirements of OAR 340, Division 224.

G22. Need to Halt or Reduce Activity Not a Defense [OAR 340-218-0050(6)(b)]

The need to halt or reduce activity will not be a defense. It will not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

G23. Duty to Provide Information [OAR 340-218-0050(6)(e) and OAR 340-214-0110]

The permittee must furnish to the Department, within a reasonable time, any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee must also furnish to the Department copies of records required to be retained by the permit or, for information claimed to be confidential, the permittee may furnish such records to the Department along with a claim of confidentiality.

G24. Reopening for Cause [OAR 340-218-0050(6)(c) and 340-218-0200]

- a. The permit may be modified, revoked, reopened and reissued, or terminated for cause as determined by the Department.
- b. A permit must be reopened and revised under any of the circumstances listed in OAR 340-218-0200(1)(a).
- c. Proceedings to reopen and reissue a permit must follow the same procedures as apply to initial permit issuance and affect only those parts of the permit for which cause to reopen exists.

G25. Severability Clause [OAR 340-218-0050(5)]

Upon any administrative or judicial challenge, all the emission limits, specific and general conditions, monitoring, recordkeeping, and reporting requirements of this permit, except those being challenged, remain valid and must be complied with.

G26. Permit Renewal and Expiration [OAR 340-218-0040(1)(a)(D) and 340-218-0130]

- a. This permit expires at the end of its term, unless a timely and complete renewal application is submitted as described below. Permit expiration terminates the permittee's right to operate.
- b. Applications for renewal must be submitted at least 12 months before the expiration of this permit, unless the Department requests an earlier submittal. If more than 12 months is required to process a permit renewal application, the Department must provide no less than six (6) months for the owner or operator to prepare an application.
- c. Provided the permittee submits a timely and complete renewal application, this permit will remain in effect until final action has been taken on the renewal application to issue or deny the permit.

G27. Permit Transference [OAR 340-218-0150(1)(d)]

The permit is not transferable to any person except as provided in OAR 340-218-0150(1)(d).

G28. Property Rights [OAR 340-200-0020 and 340-218-0050(6)(d)]

The permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations, except as provided in OAR 340-218-0110.

G29. Permit Availability [OAR 340-200-0020 and 340-218-0120(2)]

The permittee must have available at the facility at all times a copy of the Oregon Title V Operating Permit and must provide a copy of the permit to the Department or an authorized representative upon request.

ALL INQUIRIES SHOULD BE DIRECTED TO:

DEQ, Eastern Region  
475 NE Bellevue Dr., Suite 110  
Bend, OR 97701  
(541) 388-6146

## ATTACHMENT 1: RULE NUMBERING CROSS REFERENCE

Cross-reference from New Rule Numbers to Old Rule Numbers (Effective October 14, 1999)

**Attachment 1****Cross-reference from New Rule Numbers to Old Rule Numbers (Effective March 24, 2003)**

<u>New Rule Number</u>	<u>Old Rule Number</u>	<u>New Rule Number</u>	<u>Old Rule Number</u>	<u>New Rule Number</u>	<u>Old Rule Number</u>	<u>New Rule Number</u>	<u>Old Rule Number</u>
208-0110	021-0015	218-0160	028-2240	220-0160	028-2710	264-0020	023-0025
208-0200	021-0055	218-0170	028-2250	220-0170	028-2720	264-0030	023-0030
208-0210	021-0060	218-0180	028-2260	220-0180	028-2730	264-0040	023-0035
214-0300	028-1400	218-0190	028-2270	220-0190	028-2740	264-0050	023-0040
214-0310	028-1410	218-0200	028-2280	256-0200	024-0100	264-0060	023-0042
214-0320	028-1420	218-0210	028-2290	256-0300	024-0300	264-0070	023-0043
214-0330	028-1430	218-0220	028-2300	256-0310	024-0306	264-0080	023-0045
214-0340	028-1440	218-0230	028-2310	256-0320	024-0307	264-0100	023-0055
214-0350	028-1450	218-0240	028-2320	256-0330	024-0308	264-0110	023-0060
214-0360	028-1460	218-0250	028-1790	256-0340	024-0309	264-0120	023-0065
218-0010	028-2100	220-0010	028-2560	256-0350	024-0312	264-0130	023-0070
218-0020	028-2110	220-0030	028-2580	256-0360	024-0314	264-0140	023-0075
218-0040	028-2120	220-0040	028-2590	256-0370	024-0318	264-0150	023-0080
218-0050	028-2130	220-0050	028-2600	256-0380	024-0320	264-0160	023-0085
218-0060	028-2140	220-0060	028-2610	256-0390	024-0325	264-0170	023-0090
218-0070	028-2150	220-0070	028-2620	256-0400	024-0330	264-0180	023-0100
218-0080	028-2160	220-0080	028-2630	256-0410	024-0332	264-0190	023-0105
218-0090	028-2170	220-0090	028-2640	256-0420	024-0335	264-0200	023-0115
218-0100	028-2180	220-0100	028-2650	256-0430	024-0337		
218-0110	028-2190	220-0110	028-2660	256-0440	024-0340		
218-0120	028-2200	220-0120	028-2670	256-0450	024-0355		
218-0130	028-2210	220-0130	028-2680	256-0460	024-0357		
218-0140	028-2220	220-0140	028-2690	256-0470	024-0360		
218-0150	028-2230	220-0150	028-2700	264-0010	023-0022		

## ATTACHMENT 2: STATE ACID RAIN PERMIT

Issued to: Coyote Springs  
 Operated by: Portland General Electric Company  
 ORIS code: 07350  
 Effective: July 1, 2008 through June 31, 2013

**Acid Rain Permit Contents**

- 1) Statement of Basis.
- 2) SO<sub>2</sub> allowances allocated under this permit and NO<sub>x</sub> requirements for each affected unit.
- 3) Comments, notes and justification regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.
- 4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

**1) Statement of Basis**

Statutory and Regulatory Authorities: In accordance with ORS 468.020 and 468.310(2) and Title IV and V of the Clean Air Act, the Department issues this permit pursuant to OAR 340-228-0300 and 340-218-0010.

**2) SO<sub>2</sub> Allowance Allocations and NO<sub>x</sub> Requirements for each affected unit.**

		2008	2009	2010	2011	2012	2013
CT1.EU	SO <sub>2</sub> allowances	0	0	0	0	0	0
CT2.EU	SO <sub>2</sub> allowances	0	0	0	0	0	0

\*The number of allowances actually held by an affected source in a unit account may differ from the number allocated by EPA. A change in the number of allowances actually held by an affected source in a unit account does not necessitate a revision to the unit SO<sub>2</sub> allowance allocations identified in this permit (see 40 CFR §72.84)

**3) Comments, notes, and justifications:**

The Acid Rain regulations do not specify a NO<sub>x</sub> emissions limit for affected facilities that burn only natural gas or liquid fuels (e.g., distillate fuel oil).

**4) Permit application:**

Attached



For more information, see instructions and refer to 40 CFR 72.30 and 72.31

This submission is:  New  Revised

**STEP 1**

Identify the source by plant name, State, and ORIS code from NADB

Plant Name	Coyote Springs	OR State	07350 ORIS Code
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**STEP 2**

Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

Compliance Plan				
a	b	c	d	e
Boiler ID#	Unit will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units  Commence Operation Date	New Units  Monitor Certification Deadline
CTG1	Yes	No		
CTG2	Yes	No		
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

**STEP 3**

Check the box if the response in column c of STEP 2 is "Yes" for any unit

**For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.**

Plant Name (from Step 1)	Coyote Springs
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**Standard Requirements**Permit Requirements.

- (1) The designated representative of each affected source and each affected unit at the source shall:
  - (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  - (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
- (2) The owners and operators of each affected source and each affected unit at the source shall:
  - (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  - (ii) Have an Acid Rain Permit.

Monitoring Requirements.

- (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

- (1) The owners and operators of each source and each affected unit at the source shall:
  - (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
  - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  - (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  - (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8, or 72.14 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

- (1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
- (2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
  - (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

- (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  - (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  - (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
- (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

**STEP 4**  
**Read the standard requirements and certification, enter the name of the designated representative, and sign and date**

Plant Name (from Step 1)	Coyote Springs
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Recordkeeping and Reporting Requirements (cont.)

- (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
- (2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

- (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8, or 72.14, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
- (2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
- (3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
- (4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
- (5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
- (6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO<sub>x</sub> averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
- (7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8, or 72.14 shall be construed as:

- (1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
- (2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
- (3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
- (4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
- (5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

**Certification**

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Steven R. Anderson
Signature	(original form is on file at DEQ)
Date	3/12/07

STEP 5 (optional)  
Enter the source AIRS  
and FINDS identification  
numbers, if known

AIRS
FINDS