Public Notice

DEQ to hold Oct. 26 Public Hearing in Clatskanie, Requests Comments on PGE Proposed Air Quality Permit Revision

DEQ invites the public to submit written comments on the conditions of Portland General Electric's (PGE) proposed air quality permit revision to the nitrogen oxide (NOx) and carbon monoxide (CO), Best Available Control Technology (BACT) limits for the peaking turbine PTEU1 (Unit 8). In addition DEQ will hold a public hearing on this proposed permit revision on Oct. 26, 2016. See hearing details below.

Summary

PGE obtained a permit for the construction of a small 24 MW peaking turbine (PTEU1) in 2001, which allowed the turbine to operate under the significant emission rates for criteria pollutants. In 2002, PGE submitted a Prevention of Significant Deterioration -Title V significant permit modification application to allow operation of the turbine at higher emission levels. The application; which included a BACT analysis and an ambient air quality analysis. The BACT analysis included a thorough review of control technologies for particulate matter (PM/PM10), CO, NOx, sulfur dioxide (SO_2), volatile organic compounds (VOC). The turbine operates infrequently (see table 1) because, it is a peaking unit used to provide additional power when needed, and rarely operates eight consecutive hours each dispatch.

The BACT limits were established at 17 parts per million, volumetric dry (ppmvd) at 15 percent oxygen (O_2) for NO_x and 5 ppmvd at 15 percent O_2 for CO, both eight-hour rolling averages. These limits are the subject of this permit revision. The original permit did not include instructions on how to calculate the rolling average for non-consecutive operation, and did not expressly require these limits to be met during startup and shutdown.

During an inspection in September 2015, DEQ found that the turbine had exceeded the BACT limits on eight occasions when the turbine operated longer than eight consecutive hours. These events were discussed in a Pre-Enforcement Notice dated Feb. 11, 2016 and resulted in a Mutual Agreement and Order (MAO) dated March 18, 2016, in which PGE paid a $21,600.00 civil penalty for violations and DEQ agreed to clarify the permit conditions.

Per the agreement in the MAO, DEQ defined the startup and shutdown periods with respect to turbine fuel flow, defined the rolling average calculation method for non-consecutive operation, and removed startup and shutdown emissions from this calculation which are customarily not included in BACT limits. The numeric BACT limits did not change, and there are no emission increases in this proposed permit revision.

How do I participate?

To submit your comments for the public record, send them by mail, fax or email:

NWR AQ Permit Coordinator
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

Fax: 503-229-6945
Email: nwrarpermits@deq.state.or.us

Written comments are due by 5 p.m. Monday Nov. 7, 2016.

About the facility

PGE operates fossil fuel-fired power plants under its Title V Permit 05-2520 and Standard ACDP 05-2606. These plants (Beaver, Port Westward I and Port Westward II) are located at 80997 Kallunki Road, Clatskanie, OR. The PTEU1 turbine subject of this permit revision is part of the Beaver power plant which is permitted to operate under its Title V Permit 05-2520. The operation of this equipment releases particulate matter, carbon monoxide, nitrogen oxide, sulfur dioxide, volatile organic compounds, hazardous air pollutants, and greenhouse gases to the air.

How does DEQ determine permit requirements?

DEQ evaluates types and amounts of pollutants and the facility's location, and determines permit requirements according to state and federal regulations.

How does DEQ monitor compliance with the permit requirements?

This permit requires the facility to monitor pollutants using federally-approved monitoring practices and standards. Nitrogen oxide and carbon monoxide emissions from PTEU1 turbine

DEQ
State of Oregon
Department of Environmental Quality

Northwest Region
700 NE Multnomah Street
Suite 600
Portland, OR 97232

Phone: 503-229-5425
800-452-4011
Fax: 503-229-6945

Contact: Patty Jacobs, PE

Email:
jacobs.patty@deq.state.or.us

www.oregon.gov/DEQ

Search for "TV Permits, PGE, Beaver Plant"

DEQ is a leader in restoring, maintaining and enhancing the quality of Oregon's air, land and water.

DEQ provides documents electronically whenever possible in order to conserve resources and reduce costs.

If you received a hard copy of this notice, please consider receiving updates via e-mail instead. Send your request to: subscriptions@deq.state.or.us

Please include your full name and mailing address so that we can remove you from our print mailing list.

will be monitored using Continuous Emission Monitoring Systems (CEMS). PGE conducts quarterly quality assurance and quality control checks on these CEMS, and also submits semi-annual new source performance standard and semi-annual department required reports to ensure compliance with state and federal requirements. PGE must submit any excess emissions reports for this turbine upon occurrence. DEQ reviews these reports, and conducts regular inspections of the facilities and this turbine.

What happens next?

DEQ will hold a public hearing on;

Hearing details:

Wednesday Oct. 26, 2016.
Begins at 6 p.m.

Clatskanie Cultural Center
Birkenfeld Theater
75 S Nehalem Street
Clatskanie, OR

What happens after the public comment period ends?

DEQ will consider and provide responses to all comments received at the close of the comment period and/or at the public hearing. DEQ may modify provisions in the permit in accordance with the rules and statutes under the authority of DEQ. Participation in the rulemaking or the legislative process is the only way to change the rules or statutes. Ultimately, if a facility meets all legal requirements, DEQ will issue the facility's air quality permit revision following EPA review.

After the public comment period, DEQ will send the proposed permit revision to EPA. EPA will have 45 days to review the permit revision and submit any objections to DEQ in writing. If EPA has no formal objections, any person my petition EPA with an objection during the following 60 days. A petition may only be based on objections already raised during the public comment period, unless the person submitting the petition can demonstrate it was impossible or impractical to do so, or that new information is now available to justify a new objection.

Where can I get more information?

Find out more at http://www.oregon.gov/deq/Pages/publicnotice.aspx or contact:

NWR Air Quality Permit Coordinator

Phone: 503-229-5582 or 1-800-452-4011
Fax: 503-229-6945
Email: **nwraqpermits@deq.state.or.us**

For a review appointment, call 503-229-6736.

Accessibility information

Documents can be provided upon request in an alternate format for individuals with disabilities or in a language other than English for people with limited English skills. To request a document in another format or language, call DEQ in Portland at 503-229-5696, or toll-free in Oregon at 1-800-452-4011; or email deqinfo@deq.state.or.us.

DEQ-DC1

Table 1
Annual Operational Hours for PTEU1

Year	PTEU1 (Unit 8) Hours	Year	PTEU1 (Unit 8) Hours
2001	691	2009	125
2002	164	2010	3.75
2003	2.6	2011	6.2
2004	7.3	2012	11.6
2005	23.2	2013	182
2006	45.5	2014	75
2007	52.7	2015	323
2008	11		

Emissions limits

Criteria Pollutants: Table 2 below presents maximum allowable emissions of criteria pollutants for emission unit PTEU1. The current emission limit reflects maximum emissions the turbine can emit under the existing permit. The proposed emission limit reflects maximum emissions the turbine would be able to emit under the proposed permit revision. Typically, actual emissions are less than maximum limits established in a permit; however, actual emissions can increase up to the permitted limit.

Table 2

Criteria Pollutant	Current Limit for PTEU1 (tons/yr)	Proposed Limit for PTEU1 (tons/yr)
Particulate matter	9	9
Small particulate matter	9	9
Nitrogen oxides)	67	67
Sulfur dioxide	3	3
Carbon monoxide	60	60
Volatile organic compounds	3	3

For more information about criteria pollutants, go to: www.epa.gov/air/urbanair/

DEQ-DC1

State of Oregon Department of Environmental Quality

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

Northwest Region
700 NE Multnomah St., Suite 600
Portland, Oregon 97232

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

ISSUED TO:

Portland General Electric Company
c/o Environmental Services Department
121 SW Salmon Street
Portland, OR 97204

INFORMATION RELIED UPON:

Re-Opening for Cause Oct. 26, 2016

PLANT SITE LOCATION:

Beaver Plant
80997 Kallunki Road
Clatskanie, OR 97016

LAND USE COMPATIBILITY STATEMENT:

Issued by: Columbia County
Dated: Oct. 07, 1991

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Michael R Orman, E.I.T., Air Quality Manager
DEQ Northwest Region

Date

Nature of Business	SIC	NAICS
Electric power generation, greater than 25 MW, and fuel burning equipment, outside AQMA, oil fired, greater than 30 MMBtu per hour heat input	4911	221112

Acid Rain Program Identification: Plant Name: Port Westward
State: Oregon
ORIS code: 56227

RESPONSIBLE OFFICIAL		ACID RAIN DESIGNATED REPRESENTATIVE		FACILITY CONTACT PERSON	
Title:	Vice President, Power Supply/Gen. Plant Manager	Name:	Thomas Nilan	Name:	David Monro
		Title:	Designated Representative	Title:	Environmental Specialist
				Phone:	(503) 464-2437

Addendum No. 1
Reopening for Cause

In accordance with OAR 340-218-0200(10(a)(C), Oregon Title V Operating Permit number 05-2520, issued on January 21, 2009, is revised by modifying Conditions 35 and 36, (changes are highlighted in grey scale)
as follows:

Best Available Control Technology (BACT) Requirements (340-224-0070)

35. The permittee must not cause or allow the emissions of nitrogen oxides (NO_X) from emission unit PTEU1 in excess of 17 ppmvd corrected to 15% oxygen, based on an 8-hour rolling average. Nitrogen oxides must be controlled by the use of Dry Low NO_X combustion (DLN), water injection, and good combustion practices. Nitrogen oxides must be measured by CEMS. Water injection is not required during startup and shutdown. See Condition 64 for monitoring requirements.
    - 35. a. The calculation of the 8-hour rolling average is determined by averaging the emission rate during a unit operating hour with the emission rate during the previous 7 valid unit operating hours, whether consecutive or non-consecutive operating hours. This calculation does not include emissions data from any period of time where PTEU1 is in startup or shutdown, as defined in 35.b and 35.c., respectively.
    - 35.b. Startup is not to exceed the 16 minutes following commencement of fuel flow to PTEU1.
    - 35.c. Shutdown is not to exceed the 7 minutes immediately prior to ceasing fuel flow to PTEU1.

36. The permittee must not cause or allow the emissions of carbon monoxide from emission unit PTEU1 in excess of 5 ppmvd, corrected to 15% oxygen based on an 8-hour rolling average. Carbon monoxide must be controlled by catalytic oxidation, and good combustion practices. Carbon monoxide must be measured by CEMS. See Condition 65 for monitoring requirements.
    - 36. a. The calculation of the 8-hour rolling average is determined by averaging the emission rate during a unit operating hour with the emission rate during the previous 7 valid unit operating hours, whether consecutive or non-consecutive operating hours. This calculation does not include emissions data from any period of time where PTEU1 is in startup or shutdown, as defined in 36.b and 36.c. respectively.
    - 36.b. Startup is not to exceed the 16 minutes following commencement of fuel flow to PTEU1.
    - 36.c. Shutdown is not to exceed the 7 minutes immediately prior to ceasing fuel flow to PTEU1.

State of Oregon Department of Environmental Quality

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
OREGON TITLE V OPERATING PERMIT
REVIEW REPORT

Northwest Region
700 NE Multnomah Blvd., Suite 600
Portland, OR 97232

Source Information:

SIC	4911
NAICS	221112

Source Categories (Part and code) OAR 340-216-0020, Table 1	Part B, 25. Part C, 4. Part C, 5.

Compliance and Emissions Monitoring Requirements:

Unassigned emissions	NA
Emission credits	NA
Compliance schedule	NA
Source test [date(s)]	See permit conditions

COMS	NA
CEMS	Yes
PEMS	NA
Ambient monitoring	NA

Reporting Requirements

Annual report (due date)	February 15
Emission fee report (due date)	February 15
SACC (due date)	July 30
Quarterly report (due dates)	NA

Monthly report (due dates)	NA
Excess emissions report	Upon occurrence
Other reports (Acid Rain)	Yes

Air Programs

NSPS (list subparts)	GG, Db, Dc
NESHAP (list subparts)	NA
CAM	NA
Regional Haze (RH)	Yes
Synthetic Minor (SM)	NA
Part 68 Risk Management	NA
CFC	NA
RACT	NA
TACT	NA

Title V	Yes
ACDP (SIP)	NA
Major HAP source	NA
Federal major source	Yes
NSR	Yes
PSD	Yes
Acid Rain	Yes

TABLE OF CONTENTS

INTRODUCTION 4

PERMITTEE IDENTIFICATION 4

FACILITY DESCRIPTION 4

DEPARTMENT EVALUATION 4

PUBLIC NOTICE 8

LIST OF ABBREVIATIONS USED IN THIS REVIEW REPORT

ACDP	Air Contaminant Discharge Permit
AQMA	Air Quality Management Area
ASTM	American Society of Testing and Materials
BACT	Best Available Control Technology
BDT	bone dry ton
CAM	Compliance Assurance Monitoring
CEMS	continuous emissions monitoring system
CFC	Chloroflourocarbon
CFR	Code of Federal Regulations
CH_4	methane (greenhouse gas)
CMS	continuous monitoring system
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
COMS	continuous opacity monitoring system
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic feet
EF	emission factor
EPA	United State Environmental Protection Agency
EU	emissions unit
FCAA	Federal Clean Air Act
FLM	Federal Land Managers
GHG	greenhouse gas
gr/dscf	grains per dry standard cubic feet
HAP	hazardous air pollutant
ID	identification code
I&M	inspection and maintenance
MB	material balance
Mlb	1000 pounds
MM	million
N_2O	nitrous oxide (greenhouse gas)
NA	not applicable
NAICS	North American Industry Classification System
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_x	oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	operation and maintenance
Pb	lead
PCD	pollution control device
PEMS	predictive emissions monitoring system
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in size
$PM_{2.5}$	particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
RACT	Reasonably Available Control Technology
SACC	Semi-annual compliance certification
SER	Significant Emission Rate
SIC	Standard Industrial Code
SIP	State Implementation Plan
SO_2	sulfur dioxide
ST	source test
SU/SD	Startup/Shutdown
TACT	Typically Achievable Control Technology
USFS	United States Forest Service
VE	visible emissions
VMT	vehicle mile traveled
VOC	volatile organic compound

INTRODUCTION

1. On January 21, 2009, Oregon Title V Operating Permit No. 05-2520 was issued to Portland General Electric (PGE). The proposed revision in this permit action is a reopening for cause made in accordance with OAR 340-218-0200(1)(a)(C), as discussed below under Department Evaluation.

2. In accordance with OAR 340-218-0120(1)(f), this review report is intended to provide the legal and factual basis for the draft permit conditions. In most cases, the legal basis for a permit condition is included in the permit by citing the applicable regulation. In addition, the factual basis for the requirement may be the same as the legal basis. However, when the regulation is not specific and only provides general requirements, this review report is used to provide a more thorough explanation of the factual basis for the draft permit conditions.

PERMITTEE IDENTIFICATION

3. Portland General Electric Company (PGE) owns and operates two electrical power generation facilities (the Beaver Plant and the Port Westward Plant) located near Clatskanie, Oregon. The two plants are contiguous and are considered a single source by Department rules. Therefore both facilities are operating under one Title V Permit, No. 05-2520. The subject of this permit revision is one of the emission units in the Beaver Plant; hence this Review Report will only discuss that plant and equipment.

FACILITY DESCRIPTION

4. Beaver Plant
The Beaver plant, located at 80997 Kallunki Road, is a 558 MW electrical power generation facility. The facility is composed of 6 combined cycle combustion turbines (GTEU6), a steam generator, a Cleaver Brooks Watertube Boiler (Model DL-52), and one Alstom Model GT 10B natural gas fired simple cycle 24 MW turbine (PTEU1). The original 6 combustion turbines (GTEU6) were installed in 1974 as simple cycle turbines. Heat Recovery Steam Generators for each turbine were added in 1977 to convert the plant to combined cycle operation, which necessitated the need for an auxiliary boiler (ABEU1) for start-up, also added in 1977. The plant was originally built to operate on crude oil, bunker "C" oil (#6), residual oil, and distillate oil (#2). In 1980, the combustion turbines were modified to permit operation with natural gas. This modification did not trigger NSR/BACT because there was a reduction in emissions resulting from the change. The six combined cycle combustion turbines and associated auxiliary boiler primarily combust natural gas, but can also burn distillate oil. These turbines are referred to by PGE as "Units 1 – 6". "Unit 7" is the steam turbine.

The Alstom simple cycle, natural gas fired Power GT10B 24 MW combustion turbine (PTEU1) is permitted for natural gas only. PGE refers to this turbine as "Unit 8". This turbine is the subject of this permit revision, and will be the only equipment discussed in this permit action.

DEPARTMENT EVALUATION

5. PTEU1 was initially permitted under application no. 018566 (dated February 9, 2001) as a significant permit modification to the Title V Operating Permit 05-2520. The intent at that time was to operate it as a peaking unit to assist with the 2001 energy crisis. The existing annual PSELs were not increased, and the "short term PSELs" were increased by the following amounts:

Regulated Pollutant	Existing short term PSEL in lbs/hr	Proposed short term PSEL in lbs/hr	Change in short term PSEL (lbs/hr)
PM/PM_{10}	190	191	+1
CO	175	197	+22
NOx	1332	1360	+28

Regulated Pollutant	Existing short term PSEL in lbs/hr	Proposed short term PSEL in lbs/hr	Change in short term PSEL (lbs/hr)
SO_2	1591	1591	+ 0
VOC	130	140	+10

The previous Review Report indicated the following with regards to the short term hourly increases:

"The proposed increases in short term PSELs are necessary to allow operation of the proposed turbine in addition to the six existing turbines at capacity for the short term. The increase in the hourly PSEL for PM/PM10, and VOC are allowable and are expected to have no significant environmental impact. The increase in the hourly NOx limit to 1360 pounds is within the level modeled in 1982 and shown to have no significant impact. The increase in hourly CO to 197 is 11.23 pounds per hour over what was previously modeled in 1982. The previous modeling only showed a total impact from 185.7 pounds CO per hour as 0.03 mg/m^3 (1-hour average). This is far less than the Significant Air Quality Impact level of 2 mg/m^3. An increase of 11.23 pounds CO per hour above modeled rates would be no threat to exceeding the standard. Additional modeling is not required."

The Review Report concludes with the following:

"The proposed Significant Modification increases short term PSELs but not the annual PSELs. However, a NOx limitation has been established on a 12 consecutive calendar month basis to keep the source below the Significant Emissions Rate (SER) and to keep the source from becoming subject to the provisions of New Source Review (NSR)/Prevention of Significant Deterioration (PSD). This NOx limitation is specific to the proposed new peaking turbine (PTEU1). There is no other new or modified equipment at the site. The existing annual PSELs will remain in effect and emissions from the proposed construction is [sic] included in these annual limits."

This permit action was issued on May 21, 2001, after a 30 day public notice period (April 16, 2001 to May 15, 2001). DEQ Rules were changed on July 1, 2001 and short term PSELs were removed from the rules, however the turbine was permitted under the existing annual PSELs at that time and was limited to less than 40 tons NOx (SER) per 12 month rolling period by hours of operation limitations.

6. PTEU1 was originally designed as a temporary peaking unit with all emissions less than the SERs, which did not require additional modeling, as discussed above in paragraph 5. Contemporaneous to this permit action, PGE had submitted a PSD application for the much larger Port Westward I project (650MW initially) on May 14, 2001. The power shortage in the Pacific Northwest was increasing and in response, PGE determined that they wanted to keep this small peaking turbine in operation. Upon consulting with DEQ on this subject, PGE learned that there would be a conflict regarding PSD rules if both the Unit 8 and Port Westward I projects operated simultaneously. If Unit 8 operated as a permanent facility at emission rates greater than the SERs, then Unit 8 emissions had to be included in the NSR requirements triggered by the Port Westward I project. As a result, a BACT analysis and air quality analysis had to be completed for Unit 8.

In response, PGE submitted another Significant Permit Modification to the Title V permit 05-2520 "to include the Beaver Plant Unit 8 peaking turbine (emission unit PTEU1) with the Port Westward Project (proposed emission unit PWEU2) Prevention of Significant Deterioration analysis. With this latest Significant Permit Modification, this emissions unit will not be subject to the BACT requirements defined in the attached PSD analysis report by Portland General Electric." This application was submitted on April 25, 2002, and assigned application number 020159. This modification was combined with a Title V renewal (Application No. 018229) and an Administrative Amendment (Application No. 020093) and this permit was issued on September 5, 2002.

7. The BACT analysis resulted in the following original BACT limits and control technologies for PTEU1:

Pollutant	BACT
NO_X	The permittee must not cause or allow the emissions of nitrogen oxides (NO_X) from emission unit PTEU1 in excess of 17 ppmvd corrected to 15% oxygen, based on an 8-hour rolling average. Nitrogen oxides must be controlled by the use of Dry Low NO_X combustion (DLN), water injection, and good combustion practices. Nitrogen oxides must be measured by CEMS. Water injection is not required during startup and shutdown.
CO	The permittee must not cause or allow the emissions of carbon monoxide from emission unit PTEU1 in excess of 5 ppmvd, corrected to 15% oxygen based on an 8-hour rolling average. Carbon monoxide must be controlled by catalytic oxidation, and good combustion practices. Carbon monoxide must be measured by CEMS.
VOC	The permittee must not cause or allow the emissions of volatile organic compounds (VOCs) from emission unit PTEU1 in excess of 4.73 pounds per hour as methane, CH_4, based on an 8 hour rolling average. VOC emissions must be controlled by good combustion practices. VOCs must be measured in accordance with permit Condition 43.
PM/PM_{10}	The permittee must control emissions of PM, PM_{10}, and SO_2 by limiting fuel use in emission unit PTEU1 to pipe line quality natural gas. Fuel use must be monitored in accordance with permit Condition 43.a
SO_2	The permittee must control emissions of PM, PM_{10}, and SO_2 by limiting fuel use in emission unit PTEU1 to pipe line quality natural gas. Fuel use must be monitored in accordance with permit Condition 43. a.

The original BACT analysis is included as Appendix A.

8. The conclusion of the Air Quality Analysis review as part of the PSD application is as follows:

"The review of the air quality analysis of the PGE Port Westward Project, including Unit 8 operating at full capacity, using the emission rates, stack parameters, and unit locations provided in the analysis, or modified by PGE and DEQ during the review, show that impacts satisfy the following requirements:
1) NAAQS and PSD Increment for both Class II and Class I areas are satisfied.
2) Annual nitrogen and sulfur deposition are within the "significance" levels, and are acceptable.
3) Visibility impairment is less than the 5% criteria level for all Class I areas and the CRBNSA, and is acceptable.

The USFS as FLM had earlier commented that the air quality analysis for this source is acceptable, with the observation that this source together with other sources should be included in a cumulative impact analysis. The air quality analysis as reviewed demonstrates that the facility will not have adverse impacts, and the air quality analysis is acceptable."

The original Air Quality Analysis is included as Appendix B.

9. The NOx and CO BACT limits are incorporated into PGE's Title V Permit 05-2520 as Conditions 35 and 36, respectively, shown below:

> 35. The permittee must not cause or allow the emissions of nitrogen oxides (NO_X) from emission unit PTEU1 in excess of 17 ppmvd corrected to 15% oxygen, based on an 8-hour rolling average. Nitrogen oxides must be controlled by the use of Dry Low NO_X combustion (DLN), water injection, and good combustion practices. Nitrogen oxides must be measured by CEMS. Water injection is not required during startup and shutdown. See Condition 64 for monitoring requirements.

36. The permittee must not cause or allow the emissions of carbon monoxide from emission unit PTEU1 in excess of 5 ppmvd, corrected to 15% oxygen based on an 8-hour rolling average. Carbon monoxide must be controlled by catalytic oxidation, and good combustion practices. Carbon monoxide must be measured by CEMS. See Condition 65 for monitoring requirements.

10. Startup and shutdown (SU/SD) emissions were accounted for when establishing these limits, however neither permit condition expressly require that the BACT limits be met during startup and shutdown. The Review Report accompanying the 2002 PSD Permit and Title V Permit did expressly state that the NOx and CO BACT limits apply during startup and shutdown. In addition, neither condition specifies how the 8-hour rolling averages are to be calculated.

11. This turbine has not historically been dispatched often; as it is a peaking turbine and used during high power demand. It is also a simple cycle turbine which is not as efficient as the combined cycle turbines available for power production at the site.

Year	PTEU1 (Unit 8) Hours	Year	PTEU1 (Unit 8) Hours
2001	691	2009	125
2002	164	2010	3.75
2003	2.6	2011	6.2
2004	7.3	2012	11.6
2005	23.2	2013	182
2006	45.5	2014	75
2007	52.7	2015	323
2008	11		

12. During the Permit Inspection in 2015, various data was requested for the both power plants (i.e. Beaver and Port Westward I) including this turbine. Upon review of that data, it was concluded that there were six CO BACT exceedences and two NOx exceedences in 2015 for operation of the turbine equal to or greater than 8 consecutive hours. These exceedences were only because SU/SD emissions were included in the 8-hour average.

13. To address the BACT limit exceedences, a Pre-Enforcement Notice (PEN No. 2016-PEN-1366, dated February 11, 2016) was issued and referred for formal enforcement. A Mutual Agreement and Final Order (MAO) No. AQ/V-NWR-16-049 was issued on March 18, 2016 and PGE paid a $21,600.00 penalty on April 25, 2016.

The Pre-Enforcement Notice is included as Appendix C.
The Mutual Agreement and Final Order is included as Appendix D.

14. In the MAO, it was stipulated and agreed that DEQ would revise the PSD and Title V Permits to define startup as 16 minutes from the commencement of natural gas flow to the turbine and shutdown as the 7 minutes immediately prior to ceasing natural gas flow to the turbine. In addition, DEQ will define the rolling average calculation method for non-consecutive operation as using the most recent valid turbine operating hour of data and the prior 7 operating hours of valid data and remove SU/SD emissions from this calculation, which are customarily not included in (BACT) limits. The numeric (BACT) limits will not change, and there are no emission increases in this permit revision.

15. In the MAO, it was stipulated and agreed that PGE would calculate future 8-hour rolling averages for the purpose of determining compliance with the NOx and CO BACT limits using the most recent valid PTEU1 operating hour of data and the prior 7 operating hours of valid data, exclusive of emissions during SU/SD, and submit quarterly reports at the end of each calendar quarter identifying any periods of noncompliance. It should be noted that PGE has submitted two quarterly reports as of this date, neither of which had any periods of noncompliance with these conditions and limits.

16. Permit conditions 35 and 36 have been revised to reflect these agreements. DEQ has the authority to reopen this Title V/PSD permit for cause under OAR 340-218-0200(1)(a)(C), and has done so.

PUBLIC NOTICE

17. As this permit action falls under Category IV Public Notice Category, a Public Information Meeting was held in Clatskanie at the Birkenfeld Theater, 75 S. Nehalem St., on Wednesday, July 20, 2016, per OAR 340-209-0030(3)(d)(A)(ii). No members of the public attended, and no comments were received by July 22, 2016.

    The Public Information Meeting announcement is included as Attachment E.

18. This permit will be put on public notice from Sept. 19, 2016 to Nov. 07, 2016. Comments may be submitted in writing during the comment period. DEQ will hold a public hearing on Wednesday, Oct. 26, 2016 at the Birkenfeld Theater, 75 S. Nehalem St., Clatskanie, OR 97016 at 6:00 pm.

    After the comment period and hearing, DEQ will review the comments and modify the permit as may be appropriate. A proposed permit will be sent to EPA for a 45 day review period. DEQ may request and EPA may agree to an expedited review of 5 days if there were no substantive or adverse comments during the comment period.

    If EPA does not object in writing, any person may petition the EPA within 60 days after the expiration of EPA's 45-day review period to make such objection. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided for in OAR 340-218-0210, unless the petitioner demonstrates it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period.

APPENDIX A – 2002 BACT Analysis for PTEU1 (Unit 8)

APPENDIX B – 2002 Air Quality Analysis for PTEU1 (Unit 8)

APPENDIX C - Pre-Enforcement Notice No. 2016-PEN-1366, dated 2/11/2016

APPENDIX D – Mutual Agreement and Final Order No. AQ/V-NWR-16-049, dated 3/18/2016

APPENDIX E – Public Information Meeting Announcement, dated 7/20/2016

APPENDIX A

Best Available Control Technology Analysis for Alstom Power GT10B Combustion Turbine (Unit 8) at Portland General Electric Company (PGE) – Beaver Plant

The Alstom Power GT10B combustion turbine (Unit 8), which has already been installed at the Portland General Electric Company (PGE) – Beaver Plant is subject to the major new source review requirements provided in Oregon Administrative Rules (OAR) Division 224. As required by OAR 340-224-0070(1), the best available control technology (BACT) analysis for the Alstom Power GT10B combustion turbine (Unit 8) is presented in the following sections.

A.1 Top-Down BACT Methodology

In OAR 340-200-0020(14), BACT is defined as:

> ...an emission limitation, including, but not limited to, a visible emission standard, based on the maximum degree of reduction of each air contaminant subject to regulation under the Act which would be emitted from any proposed major source or major modification which, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such air contaminant...

In a memorandum dated December 1, 1987, the U.S. Environmental Protection Agency (EPA) Assistant Administrator for Air and Radiation implemented the "top-down" method for determining BACT. As described in EPA's *Draft New Source Review Workshop Manual* (October 1990), the five steps of a top-down BACT analysis are:

1. **Identify all available control techniques applicable to the proposed source, including Lowest Achievable Emission Rate (LAER) techniques.** Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Techniques must be commercially available to be considered. Per page B-11 of the *Draft New Source Review Workshop Manual,* "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." On page B.18 of the *Draft New Source Review Workshop Manual,* EPA again specifies that a technology must be commercially available to be considered: "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A

source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique."

2. **Eliminate technically infeasible options.** The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific factors. This demonstration should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emission unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.
3. **Rank remaining control techniques by control effectiveness.** This ranking should include control efficiencies, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts. If the top control alternative is chosen, then cost and other detailed information in regard to other control options need not be provided.
4. **Evaluate the most effective controls and document results, including a case-by-case consideration of energy, environmental, and economic impacts.** If the top control alternative is selected, impacts of unregulated air pollutants or impacts in other media are considered to determine if the selection of an alternative control option can be justified. If the top control option is not selected as BACT, evaluate the next most effective control option.
5. **Select BACT**, which will be the most effective option not rejected in Step 4.

As part of the BACT analysis, Steps 1 through 5 have been completed for PM, PM_{10}, NO_X, CO, VOC, and SO_2 emissions from the Alstom Power GT10B combustion turbine (Unit 8).

A.2 BACT for NO_X

A.2.1 Theoretical Formation and Control of NO_X

EPA, in Technical Bulletin EPA 456/F-99-006R, *Nitrogen Oxides (NO_X), Why and How They are Controlled* (EPA 1999), describes three pathways for NO_X formation during fuel combustion. First, thermal NO_X is caused by the oxidation of nitrogen in ambient air and is controlled by the molar concentrations of nitrogen and oxygen and the temperature of combustion. Second, fuel NO_X results from the oxidation of already-ionized nitrogen contained in the fuel. Third, prompt NO_X is formed from the oxidation of molecular nitrogen in air after the nitrogen combines with fuel in fuel-rich conditions which exist during combustion. During natural gas combustion, thermal NO_X is the predominant pathway.

EPA (EPA 1999) describes six primary methods for controlling NO_X from combustion of fossil fuels: (1) reducing the peak temperature during combustion, (2) reducing residence time at peak temperature during combustion, (3) chemical reduction of NO_X after its formation, (4) oxidizing NO_X with subsequent absorption after its formation, (5) removing nitrogen from inlet air or fuel before combustion, and (6) using a sorbent in combustion chambers or exhaust ductwork.

Reduction of peak temperature or residence time are generally accomplished through (a) injection of water or steam into the high temperature region of the flame, (b) use of dry low-NO_X technology to limit flame temperature and excess oxygen, or (c) use of a catalyst to oxidize the fuel instead of flame combustion. The proprietary XONON™ Cool Combustion technology, a catalytic technology that combusts fuel flamelessly, is currently being developed and marketed by Catalytica Energy Systems (Catalytica).

Chemical reduction is the only commercially available method of reducing NO_X after its formation. The two primary systems for reduction of NO_X are selective catalytic reduction (SCR) which uses ammonia and the proprietary $SCONO_X^{TM}$ system (catalytic absorption). Selective non-catalytic reduction (SNCR) which uses ammonia or urea can also be used for chemically reducing the NO_X.

Oxidation/absorption and use of sorbents in combustors or ductwork are not techniques commercially available at this time nor readily applied to combustion turbines due to the very large volume of exhaust gas generated. Removal of nitrogen from inlet air or natural gas are not practical methods for commercial applications.

A.2.2 Gas Turbine BACT for NO_X

A.2.2.1Previous BACT Determinations

A database search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) for natural gas-fired combustion turbine [Source Classification Code (SCC) Code 20100201] projects from 1997 to present is summarized in Table A-1. For realistic comparison purposes, only the smaller size combustion turbine projects, i.e. ones that have a power output less than approximately 50 megawatts (MW) or a maximum heat input rating less than approximately 500 million British thermal units per hour (mmBtu/hr), have been listed in Table A-1. Pollution prevention, dry low-NO_X combustion, water injection, and steam injection are the various control technologies that are listed in the database. Some of the older BACT determinations, i.e. earlier than 1997, which were specific to California, listed SCR or $SCONO_X^{TM}$ as the BACT technologies for similar size combustion turbines. Of the various projects listed in Table A-1, a BACT limitation of 15 parts per million by volume, dry (ppmvd) NO_X (corrected to 15 percent O_2), is the most stringent. Most of the projects that have concluded water injection to be the BACT have an emission limitation of 25 ppmvd NO_X at 15 percent O_2.

A.2.2.2Technological Feasibility

Five different techniques were evaluated for the control of NO_X emissions from the Alstom Power GT10B combustion turbine. The details for various techniques and their technical feasibility in applying them to the combustion turbine at PGE – Beaver Plant are described below.

A.2.2.2.1 Catalytic Reduction. The primary type of catalytic reduction system for NO_X is SCR and involves the injection of ammonia into the flue gas stream where it selectively reacts with NO_X in the presence of oxygen (O_2) and a catalyst to form molecular nitrogen and water. The $SCONO_X^{TM}$ system uses a coated catalyst to oxidize and adsorb NO_X (as NO_2) onto the catalyst but does not actually use the catalyst to reduce the nitrogen compounds. It will be discussed separately in Section A.2.2.2.2.

TABLE A-1
Recent NO_X Limits for Smaller Size Combustion Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	Combustion Turbine Type	Combustion Turbine Rating	Fuel Used	BACT/LAER
25 ppmvd @ 15% O_2	Pollution Prevention, Fuel Oil Sulfur Content <=0.05% by Weight, Dry Low NO_X Combustor Design Firing Gas and Dry Low NO_X Combustor with Water Injection Firing Oil	03/12/1997	Mead Coated Board, Inc., Alabama	Combined Cycle	25 MW 568 mmBtu/hr	Natural Gas with Distillate Oil as Backup	BACT
25 ppm @ 15% O_2	Pollution Prevention, Steam Injection	02/28/2000	Wrightsville Power Facility, Arkansas	LM6000 Combustion Turbine with Duct Burner	46 MW	-	BACT
None	Water Injection, Selective Catalytic Reduction	05/30/2001	TransAlta Centralia Generation, LLC, Washington	GE LM6000 Sprint Combustion Turbine with HRSG	47 MW 466 mmBtu/hr	Natural Gas	Other
15 ppmvd above 70% load	Pollution Prevention Built Into Equipment	01/04/1999	Colorado Springs Utilities, Colorado	-	30 MW	Natural Gas	BACT
25 ppm @ 15% O_2	Dry Low NO_X Burners	02/27/1998	Two Elk Generation Partners, Limited Partnership, Wyoming	Stationary Turbine	33.3 MW	-	BACT
150 ppmvd	Pollution Prevention, CZ Liner Lean-Head Combustion Technology	02/13/1998	Kuparuk Central Production Facility, Alaska	GE Frame 6 Model PG6551 (B)	38.9 MW	Natural Gas	BACT
15 ppm @ 15% O_2	Pollution Prevention, Dry Low NO_X Combustor	12/28/1999	Orange Cogeneration LP, Florida	-	368.3 mmBtu/hr	Natural Gas	BACT
15 ppm @ 15% O_2	Pollution Prevention, Dry Low NO_X Combustor	12/21/1999	Kissimmee Utility Authority, Florida	-	367 mmBtu/hr	Natural Gas	BACT
25 ppm @ 15% O_2	Add-on Control Equipment, Water Injection	09/29/2000	Handsome Lake Energy, Pennsylvania	-	50 MW	Natural Gas	BACT
34 lb/hr	Pollution Prevention, Dry Low NO_X Combustion	03/01/2000	Black Hills Power & Light – Neil Simpson II, Wyoming	-	40 MW 307 mmBtu/hr	Natural Gas	BACT

Note: NO_X concentration units are presented as specifically noted in the database. No corrections to inconsistencies were made.

SCR involves the injection of ammonia into the flue gas stream where it selectively reacts with NO_X in the presence of O_2 and a catalyst to form molecular nitrogen and water. Because the pertinent reactions normally proceed at temperatures between 1,600 and 1,800°F, a catalyst is used to promote the reactions at lower temperatures. Although the exact catalyst composition is proprietary, the use of base metal oxides for both the active and support materials has been generally acknowledged (vanadium pentoxide, titanium dioxide, zeolite, or noble metal). Newer, more sulfur-resistant ceramic catalysts have recently been used. The temperature range required for this catalytic reduction process is typically between 570 and 750°F. For combined-cycle combustion turbines, this temperature range usually exists within the high pressure section of the HRSG, in which case the high pressure evaporator tube bank of the HRSG is split to accommodate the SCR unit. If the catalyst bed is not located in the proper temperature zone of the HRSG, either the reaction efficiency will be reduced if the temperature is too low, resulting in increased ammonia slip, or the catalyst may be damaged if the temperature is too high.

SCR is considered a proven technology for base loaded natural gas-fired combustion turbine/ HRSG operation. Base loaded units operate at a near constant load thereby providing a constant energy output throughout their yearly operation. The temperature profile in the HRSG of a base loaded turbine remains constant with time throughout the turbine operation. Since the catalyst can only be located in one fixed place within the HRSG, it would experience near constant temperatures that are within the design temperature window of the catalyst.

The Alstom Power GT10B combustion turbine at PGE – Beaver Plant is a simple cycle combustion turbine with a stack exit temperature of approximately 990°F. Based on the information provided by the manufacturer at the time of installation of the combustion turbine, the GT10B combustion turbines were typically not equipped with SCR technology for control of NO_X emissions, because of technical difficulties and the cost issues. Therefore, this technology was originally not technically feasible for use on the Alstom Power GT10B combustion turbine at the PGE - Beaver Plant. Recent advances in SCR control technology have made it technically feasible to install what is now called hot SCR control technology, on simple cycle combustion turbines with high stack gas exit temperatures. Therefore, hot SCR is being considered as a technically feasible control technology for control of NO_X emissions from the Alstom Power GT10B combustion turbine.

A.2.2.2.2 SCONO$_X$™. ABB Alstrom Power Environmental Systems (AAP) produces the SCONO$_X$™ system for smaller size combustion turbines (from 10 MW to 100 MW) under a licensing agreement from Goal Line Environmental Technologies. Unlike SCR, the SCONO$_X$™ system does not use ammonia. Instead, the SCONO$_X$™ system uses a coated catalyst to oxidize nitrogen oxide (NO) to nitrogen dioxide (NO_2) and to adsorb NO_2 onto the coating on catalyst. The system consists of a catalyst bed installed in the HRSG at a location where the temperature is between 280 and 700°F.

The SCONO$_X$™ system is a feasible control technology for smaller size combined-cycle combustion turbines, where the catalyst bed is installed in the HRSG at a location where the temperature is between 280 and 700°F. Because the Alstom Power GT10B combustion turbine at PGE - Beaver Plant is a simple cycle combustion turbine, installation of a SCONO$_X$™ system is not considered technically feasible.

A.2.2.2.3 Post-Combustion NO_X Oxidation. The Cannon low temperature oxidation (LTO) technology was primarily developed to control emissions from steam boilers. The basic

operation of the LTO system injects ozone into a cooled exhaust gas (approximately 300°F) to oxidize NO_X, CO, and SO_2 to nitrates, carbonates, and sulfates. These higher oxides are absorbed by a dilute nitric acid solution in a scrubber. Testing on a natural gas-fired boiler has shown NO_X concentrations below 3.5 ppmvd at 3 percent oxygen, and vendor literature indicates NO_X guarantees of less than 4 ppmvd.

The LTO system has been demonstrated on relatively small natural gas-fired boilers ranging in size from 4.1 to 16.7 million British thermal units per hour (mmBtu/hr). The volume of exhaust gas from a 16.7 mmBtu/hr boiler will be approximately 145,457 standard dry cubic feet per hour (SDCFH). The exhaust gas volume from the Alstom Power GT10B combustion turbine at the PGE – Beaver Plant will be up to 434,615 actual cubic feet per minute (acfm). This will require a drastic scale-up of the LTO technology. Additionally, the scrubber solution would result in the generation of additional pollution (scrubber waste) and would require disposal. Cannon LTO technology literature indicates the scrubber waste can be discharged to sanitary sewer systems, but this option has not been verified and would directly impact costs.

Because it has never been scaled up to the scale required for the Alstom Power GT10B combustion turbine, the LTO technology was rejected as a feasible NO_X control measure for the Alstom Power GT10B combustion turbine, installed at the PGE – Beaver Plant.

A.2.2.2.4 Dry Low-NO_X Combustion Technology. Two types of dry low-NO_X (DLN) combustion technology are lean premix combustion and catalytic combustion. Both are described below.

- **Lean Premix Combustion.** The lean premix type is the most popular DLN combustor available. Conventional combustors are diffusion controlled. The fuel and air are injected separately with combustion occurring at the stoichiometric interfaces. This method of combustion results in combustion "hot spots" which produce higher levels of NO_X. In the lean premix combustor, the air and fuel are mixed before they enter the combustor. Lean premix combustors have only been developed for gas-fired turbines, and the more advanced designs are capable of achieving a 70 to 90 percent NO_X reduction with NO_X concentration from 9 to 25 ppmvd. This technology has been incorporated into the Alstom Power GT10B combustion turbine design, installed at PGE – Beaver Plant. Therefore, the lean premix DLN combustion technology is considered technically feasible.

- **Catalytic Combustion.** Another type of DLN combustor on the market is a catalytic combustor, such as Catalytica's XONON™, that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst as combustion occurs at much lower temperatures when compared to a standard combustor. This reduction in the combustion temperature greatly reduces the formation of thermal NO_X. Emissions of NO_X from catalytic combustors are typically below 5 ppmvd. Extensive information about the Xonon cool combustion technology is available on Catalytica's website (www.catalyticaenergy.com). A prototype of the Xonon combustion system (Xonon-1) was installed on a 1.5 megawatt (MW) Kawasaki M1A-13A gas turbine, and was operated in a test cell at Tulsa, Oklahoma. During 1,100 operating hours and 220 starts, Xonon was proven to reduce NO_X to less than 2.5 ppm. A 1.5 MW Kawasaki turbine equipped with Xonon-1 was then installed at Silicon Valley Power in late 1998. A commercial-ready Xonon-2 equipped 1.5 MW turbine began operation at Silicon Valley Power in July 1999 and to this date, this operation has accumulated over 7,400 operating hours. Average NO_X emissions at full load have been demonstrated to be less than 2 ppm

corrected to 15 percent O_2. However, catalytic combustors have not been applied commercially to combustion turbines in the Alstom Power GT10B size range.

The XONON™ system is not commercially available for the Alstom Power GT10B combustion turbine or comparable equipment at this time. Therefore, this technology is not considered feasible for use on the combustion turbine already installed at the PGE - Beaver Plant and is eliminated from further consideration in this BACT analysis.

A.2.2.2.5 Water/Steam Injection. The injection of water or steam into the combustor of a combustion turbine quenches the flame and absorbs heat thereby reducing the combustion temperature. This temperature reduction minimizes the formation of thermal NO_X. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts thereby increasing the combustion turbine's maximum power output. The use of water or steam injection generally reduces NO_X emissions to 25 ppmvd at 15 percent O_2 when firing natural gas. Aeroderivative combustion turbines can accommodate higher water or steam injection rates, achieving NO_X levels below 25 ppmvd without any detrimental effects to the combustion turbine components.

Because of its technically feasibility in reducing NO_X emissions from combustion turbines in the similar size range as Alstom Power GT10B combustion turbine, water/steam injection technology will be considered further in this BACT analysis.

A.2.2.3Ranking of Remaining Alternatives

Based on previous BACT determinations and technical feasibility discussed above, the following alternatives are advanced for ranking: hot SCR, dry low-NO_X combustion, and water/steam injection. These technologies are ranked in Table A-2.

TABLE A-2
NO_X Control Technology Ranking for Smaller Size Combustion Turbines

Technology	Emission Rate (ppmvd @ 15% O_2, annual average)	Technically Feasible?
Hot SCR	2.5 – 9.0	Yes
DLN Combustion	15.0 – 25.0	Yes
Water/Steam Injection	15.0	Yes

A.2.2.4 Evaluation of Remaining Alternatives

As per the top-down methodology, the economic, energy, and environmental impacts of the various alternatives that were ranked in the previous section should be evaluated to determine the most effective control technique that would be selected as BACT for NO_X emissions from the Alstom Power GT10B combustion turbine.

The installation of the hot SCR control equipment results in an estimated total annual cost of approximately $1,200,000. The total annual cost has been assumed to be equal to the capital cost for the initial purchase of the hot SCR control equipment. Without the use of water injection for control of NO_X emissions, Alstom Power has guaranteed the NO_X emissions from the GT10B combustion turbine to be less than 25 ppmvd at 15% O_2. When water injection is used, NO_X emissions have been guaranteed to be less than 15 ppmvd at 15% O_2. After hot SCR is used, NO_X emissions can be reduced to be as low as 2.5 ppmvd at 15% O_2

(depending on the amount of ammonia that is used for NO_X control). Uncontrolled emissions at 25 ppmvd at 15% O_2 are approximated to be about 27.9 lb/hr. The controlled emissions after water injection at 15 ppmvd at 15% O_2 are approximated to be about 16.74 lb/hr, and the controlled emissions after hot SCR at 2.5 ppmvd at 15% O_2 are approximated to be about 2.79 lb/hr. Based on 8,760 hours of operation per year for the combustion turbine, the total reduction in NO_X emissions as a result of hot SCR control is approximately 61.101 tons per year, resulting in a cost effectiveness of about $19,640 per ton.

The cost effectiveness of $19,640 per ton of NO_X emissions reduction appears to be a lot higher than the threshold that is typically used by regulatory agencies in determining the BACT requirements. Use of hot SCR control technology has therefore been determined to be economically infeasible for the Alstom Power GT10B combustion turbine at the PGE - Beaver Plant.

Evaluation of the economic, energy, and environmental impacts of DLN combustion control technology and water/steam injection control technology becomes unnecessary because PGE has already decided to use both these technologies for control of NO_X emissions from the Alstom Power GT 10B combustion turbine at the PGE - Beaver Plant. Use of water injection does result in higher CO and VOC emissions, but these emissions are further controlled using an oxidation catalyst.

A.2.2.5Combustion Turbine NO_X BACT Summary

DLN combustion and water injection at 15 ppmvd (corrected to 15 percent O_2), based on a 24-hour averaging basis, is proposed as BACT for the Alstom Power GT10B combustion turbine at PGE – Beaver Plant.

A.3 BACT for CO

A.3.1 Theoretical Formation and Control of CO

CO emissions result from incomplete fuel combustion, which can result from insufficient residence time at high temperature or incomplete mixing of fuel and air. In gas turbines, the use of dilution air as a NO_X control method and operation at low or medium loads can increase CO emissions. Thus many NO_X control methods such as water/steam injection, lean premix combustion, and low flame temperatures can increase CO and VOC emissions. A good combustor design will minimize the formation of CO and VOCs while reducing the combustion temperature and NO_X emissions.

Catalytic combustion could be used to balance the conflicting NO_X and CO control mechanisms during combustion. The system would use a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission factors.

Finally, catalytic oxidation could be used to oxidize CO to CO_2 after combustion. Catalysts for these systems usually include precious metals such as platinum, palladium, or rhodium. The oxidation reaction occurs without the need to add additional reactants.

A.3.2 Combustion Turbine BACT for CO

A.3.2.1Previous BACT Determinations

A database search of EPA's RBLC for natural gas-fired combustion turbine (SCC Code 20100201) projects from 1997 to present is summarized in Table A-3. For realistic

comparison purposes, only the smaller size combustion turbine projects, i.e. ones that have a power output less than approximately 50 MW or a maximum heat input rating less than approximately 500 mmBtu/hr, have been listed in Table A-3. Pollution prevention, proper design, good combustion practices, and catalytic oxidation are the various control technologies that are listed in the database. Of the various projects listed in Table A-3, a BACT limitation of 1.5 ppmvd CO, corrected to 15 percent O_2, 8-hour average, appears to be the most stringent. This project identifies catalytic oxidation as the BACT for the combustion turbines. Another project that identifies catalytic oxidation to be the BACT has an emission limitation of 25 ppm CO at 15 percent O_2. All other projects that have identified pollution prevention, proper design, and good combustion practices as BACT have CO emission limits ranging between 25 to 66 ppm at 15 percent O_2 or from 21 to 70 lb/hr. There generally appears to be no correlation between the size of the combustion turbines, control technology used, and CO emission limits.

A.3.2.2Technological Feasibility

Three different techniques for the control of CO emissions from the combustion turbines were evaluated. The details for various techniques and their technical feasibility in applying them to the Alstom Power GT10B combustion turbine at PGE – Beaver Plant are described below.

A.3.2.2.1 Catalytic Oxidation. The $SCONO_X^{TM}$ catalyst will oxidize CO to CO_2 in addition to oxidizing NO to NO_2 (prior to subsequent adsorption and reduction to N_2). Based on discussions with AAP, reduction of CO to approximately 3 ppmvd (corrected to 15 percent O_2) is achievable with a $SCONO_X^{TM}$ system designed to reduce NO_X from 25 ppmvd to 2.5 ppmvd (corrected to 15 percent O_2). However, as described above, the $SCONO_X^{TM}$ system is a feasible control technology only for combined-cycle combustion turbines, where the catalyst bed is installed in the HRSG at a location where the temperature is between 280 and 700°F. Because the Alstom Power GT10B combustion turbine at PGE - Beaver Plant is a simple cycle combustion turbine, installation of a $SCONO_X^{TM}$ system is not technically feasible.

Other catalytic oxidation systems, such as those manufactured by Englehard, have a more proven track record at locations where LAER was required. Emission guarantees as low as 3 ppmvd (corrected to 15 percent O_2) have been permitted for larger combined-cycle

TABLE A-3
Recent CO Limits for Smaller Size Combustion Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	Combustion Turbine Type	Combustion Turbine Rating	Fuel Used	BACT/LAER
28 ppmvd @ 15% O_2	Pollution Prevention, Proper Design and Good Combustion Practices	03/12/1997	Mead Coated Board, Inc., Alabama	Combined Cycle	25 MW 568 mmBtu/hr	Natural Gas with Distillate Oil as Backup	BACT
66 ppm @ 15% O_2	Pollution Prevention, Steam Injection / Good Combustion	02/28/2000	Wrightsville Power Facility, Arkansas	LM6000 Combustion Turbine with Duct Burner	46 MW	-	BACT
35 ppm @ 15% O_2	Pollution Prevention, Good Combustion	03/27/1997	Colo. Power Partners – Brush Cogen Fac, Colorado	Cogeneration Turbine with Duct Burner	385 mmBtu/hr	-	BACT
1.5 ppmvd @ 15% O_2 (8-hr Average)	Catalytic Oxidation	05/30/2001	TransAlta Centralia Generation, LLC, Washington	GE LM6000 Sprint Combustion Turbine with HRSG	47 MW 466 mmBtu/hr	Natural Gas	BACT
70 lb/hr	Pollution Prevention, Combustion Design and Construction	03/07/1997	Formosa Plastics Corporation, Louisiana	Cogeneration Turbine / HRSG	450 mmBtu/hr	Natural Gas	BACT
25 ppm @ 15% O_2	No Controls Feasible	02/27/1998	Two Elk Generation Partners, Limited Partnership, Wyoming	Stationary Turbine	33.3 MW	-	Other
30 ppmvd	Pollution Prevention, Good Combustion	12/28/1999	Orange Cogeneration LP, Florida	-	368.3 mmBtu/hr	Natural Gas	BACT
40 lb/hr	Pollution Prevention, Good Combustion Practices	12/21/1999	Kissimmee Utility Authority, Florida	-	367 mmBtu/hr	Natural Gas	BACT
25 ppm @ 15% O_2	Add-on Control Equipment, High Temperature Oxidation Catalyst	09/29/2000	Handsome Lake Energy, Pennsylvania	-	50 MW	Natural Gas	BACT
21 lb/hr	Pollution Prevention, Good Combustion Practices	03/01/2000	Black Hills Power & Light – Neil Simpson II, Wyoming	-	40 MW 307 mmBtu/hr	Natural Gas	BACT

Note: CO concentration units are presented as specifically noted in the database. No corrections to inconsistencies were made.

combustion turbines.

Traditionally, combustion turbine vendor estimates for CO and VOC emissions tended to be very conservative. As a result, early CO BACT analysis showed that the installation of an oxidation catalyst was cost effective. However, as actual source testing data was generated for combustion turbines without oxidation catalysts, the results showed that the combustion turbine vendor's CO emission estimates were significantly greater than the actual CO emissions measured. Regardless of this fact, oxidation catalysts will be considered technologically feasible and will be advanced for ranking.

A.3.2.2.2 Catalytic Combustion. The XONON™ system, manufactured by Catalytica, shows promise in future applications for simultaneously reducing NO_X, CO, and VOC emissions. As discussed in the BACT for NO_X section of this document, the XONON™ system has been tested on very small size combustion turbines and is not currently available for larger combustion turbines such as the Alstom Power GT10B combustion turbine. This technology is not commercially available, and thus is not technically feasible for the Alstom Power GT10B combustion turbine at the PGE – Beaver Plant.

A.3.2.2.3 Efficient Combustion. Good combustor design and good operating practices are the most common methods for controlling CO emissions from combustion turbines.

A.3.2.3Ranking of Remaining Alternatives

The remaining alternatives are catalytic oxidation and good combustor design. These technologies are ranked in Table A-4.

TABLE A-4
CO Control Technology Ranking for Smaller Size Combustion Turbines

Technology	Emission Rate (ppmvd @ 15% O_2)	Technically Feasible?
Catalytic Oxidation plus Good Combustor Design	1.5 – 25	Yes
Good Combustor Design	25 – 66	Yes

A.3.2.4 Evaluation of Remaining Alternatives

The economic, energy, and environmental impacts of the various alternatives that were ranked in the previous section were evaluated to determine the most effective control technique that would be selected as BACT for CO emissions from the smaller size combustion turbines.

A.3.2.4.1 Catalytic Oxidation. The economic, energy, and environmental impacts associated with the use of catalytic oxidation control technique are discussed below.

A.3.2.4.1.1 Catalytic Oxidation Economic Analysis. The installation of the oxidation catalyst equipment results in an estimated total annual cost of approximately $750,000. The total annual cost has been assumed to be equal to the capital cost for the initial purchase of the catalytic oxidation equipment. Without the use of water injection for control of NO_X emissions and before using catalytic oxidation, Alstom Power has guaranteed the CO emissions from the GT10B combustion turbine to be less than 35 ppmvd at 15% O_2. When water injection is used, CO emissions before catalytic oxidation could be as high as 70 to 200 ppmvd at 15% O_2. After catalytic oxidation is used, CO emissions are guaranteed to be less than 10 ppmvd at 15% O_2, but could be as low as 3 ppmvd at 15% O_2. Uncontrolled emissions at 35 ppmvd at 15% O_2 are approximated to be about 22 lb/hr, whereas controlled emissions at 10 ppmvd at 15% O_2 are approximated to be about 6.286 lb/hr. Based on

8,760 hours of operation per year for the combustion turbine, the total reduction in CO emissions is approximately 68.827 tons per year, resulting in a cost effectiveness of about $10,897 per ton.

The cost effectiveness of $10,897 per ton of CO emissions reduction appears to be a lot higher than the threshold that is typically used by regulatory agencies in determining the BACT requirements, however PGE has already decided that it will install the oxidation catalyst for controlling CO emissions. PGE is requesting a limit of 10 ppmvd corrected to 15 percent O_2 on a 8-hour rolling average basis.

A.3.2.4.1.2 Catalytic Oxidation System Energy Impacts. As with other add-on control devices, there are energy impacts associated with the use of oxidation catalysts. There is a peak power output penalty and a fuel penalty associated with use of the oxidation catalyst. Use of the catalytic oxidation system creates additional pressure drop in the combustion turbine exhaust. As described above, this can result in (1) an increase in energy consumption resulting from increased heat rate, which may be shown as a reduction of electrical generation resulting from the application of the control technology due to increased parasitic load or back pressure and (2) the reduced unit availability, which may be due to additional maintenance requirements for the applied control technology.

A.3.2.4.1.3 Environmental Impacts of Combustion Turbine Catalytic Oxidation. The primary environmental impact associated with the use of an oxidation catalyst is an increase in PM_{10} emissions due to the additional oxidation of sulfur present in the combustion turbine exhaust gas. The combustion turbine oxidizes any sulfur compounds in the natural gas (either naturally occurring or added as an odorant) to SO_2. The SO_2 would be further oxidized to SO_3 across the oxidation catalyst and would be emitted as a sulfate, which is considered PM. Disposal of the spent catalysts could also represent an environmental impact. The catalysts used must be replaced approximately every three to six years. The catalyst contains heavy metals that may cause the spent catalyst to be considered a hazardous waste. However, catalyst vendors typically accept return of spent catalysts for recovery and reuse of the catalysts' precious metals.

A.3.2.4.1.4 Summary of Catalytic Oxidation. Catalytic oxidation presents secondary environmental considerations including increased pressure drop, which lowers combustion turbine fuel efficiency, and increased PM emissions. However, despite its high cost and secondary environmental considerations, catalytic oxidation will be used as the BACT for control of CO emissions from the Alstom Power GT10B combustion turbine at PGE - Beaver Plant.

A.3.2.4.2 Good Combustor Design. PGE - Beaver Plant would use state of the art combustor design to minimize CO emissions before they are controlled further using catalytic oxidation. Because PGE has already selected catalytic oxidation as the BACT for CO emissions from the combustion turbine, an evaluation of the economic, energy, and environmental impacts of good combustor design is not necessary as per the top-down methodology. In any case, no adverse energy or environmental impacts can be attributed to good combustor design.

A.3.2.5Combustion Turbine CO BACT Summary

The available methods for control of CO emissions from the combustion turbine are good combustor design and catalytic oxidation. Both good combustor design and catalytic oxidation would be used for the Alstom Power GT10B combustion turbine at PGE – Beaver Plant.

Good combustor design and catalytic oxidation at 10 ppmvd (corrected to 15 percent O_2), based on a 8-hour rolling average basis, is proposed as BACT for the Alstom Power GT10B combustion turbine at PGE – Beaver Plant.

A.4 BACT for VOCs

A.4.1 Theoretical Formation and Control of VOCs

As with carbon monoxide emissions, VOC emissions result from incomplete fuel combustion, which can result from insufficient residence time at high temperature or incomplete mixing of fuel and air. In gas turbines, the use of dilution air as a NO_X control method and operation at low or medium loads can increase VOC emissions. Thus many NO_X control methods such as water/steam injection, lean premix combustion, and low flame temperatures can increase CO and VOC emissions. A good combustor design will minimize the formation of CO and VOCs while reducing the combustion temperature and NO_X emissions.
Catalytic combustion could be used to balance the conflicting NO_X and CO/VOC control mechanisms during combustion. The system would use a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission factors.
Finally, catalytic oxidation could be used to oxidize VOCs to CO_2 and water after combustion. Catalysts for these systems usually include precious metals such as platinum, palladium, or rhodium. The oxidation reaction occurs without the need to add additional reactants.

A.4.2 Combustion Turbine BACT for VOC

A.4.2.1 Previous BACT Determinations

A database search of EPA's RBLC for natural gas-fired combustion turbine (SCC Code 20100201) projects from 1994 to present is summarized in Table A-5. For realistic comparison purposes, only the smaller size combustion turbine projects, i.e. ones that have a power output less than approximately 50 MW or a maximum heat input rating less than approximately 500 mmBtu/hr, have been listed in Table A-5. Pollution prevention, proper combustor design, good combustion practices, catalytic oxidation, and use of natural gas as

TABLE A-5
Recent VOC Limits for Smaller Size Combustion Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	Combustion Turbine Type	Combustion Turbine Rating	Fuel Used	BACT/LAER
8 lb/hr	Pollution Prevention, Natural Gas as Primary Fuel	10/02/1997	Northern California Power Agency, California	GE Frame 5 Gas Turbine	325 mmBtu/hr	Natural Gas	LAER
1.1 lb/hr	Pollution Prevention, Oxidation Catalyst	08/19/1994	Sacramento Cogeneration Authority P&G, California	Simple Cycle Gas Turbine, LM6000	421.4 mmBtu/hr	-	BACT
1.1 lb/hr	Add-on Control Equipment, Oxidation Catalyst	08/19/1994	Sacramento Cogeneration Authority P&G, California	Combined Cycle Gas Turbine, LM6000	421.4 mmBtu/hr	-	BACT
0.75 lb/hr (1-hr Average)	Oxidation Catalyst, Combustion Controls, Combustor Design, Use of Natural Gas	05/30/2001	TransAlta Centralia Generation, LLC, Washington	GE LM6000 Sprint Combustion Turbine with HRSG	47 MW 466 mmBtu/hr	Natural Gas	BACT
0.6 ppmvd @ 15% O_2	Add-on Control Equipment, Oxidation Catalyst	08/19/1994	Bear Mountain Limited, California	Cogeneration Turbine, GE LM5000	48 MW	-	BACT
10 ppmvd	Pollution Prevention, Good Combustion	12/28/1999	Orange Cogeneration LP, Florida	-	368.3 mmBtu/hr	Natural Gas	BACT
3.6 lb/hr	Pollution Prevention, Combustion Controls, Fuel Selection	02/24/1994	International Paper, Louisiana	Cogeneration Turbine/HRSG	338 mmBtu/hr	-	BACT
1.4 lb/hr	No Controls Feasible	12/21/1999	Kissimmee Utility Authority, Florida	-	367 mmBtu/hr	Natural Gas	BACT
3.2 lb/hr	Add-on Control Equipment, High Temperature Oxidation Catalyst	09/29/2000	Handsome Lake Energy, Pennsylvania	-	50 MW	Natural Gas	BACT
4.4 lb/hr	Pollution Prevention, Good Combustion Practices	04/22/1994	Fleetwood Cogeneration Associates, Pennsylvania	GE LM6000	360 mmBtu/hr	Natural Gas	BACT

Note: VOC concentration units are presented as specifically noted in the database. No corrections to inconsistencies were made.

fuel are the various control technologies that are listed in the database. Of the various projects listed in Table A-5, a BACT limitation of 0.6 ppmvd VOC, corrected to 15 percent O_2, appears to be the most stringent. However, it is difficult to compare and determine which emission limit represents the most stringent control because most of the VOC emission limits are in pounds per hour (lb/hr) and there generally appears to be no correlation between the size of the combustion turbines, control technology used, and VOC emission limits.

A.4.2.2Technological Feasibility

As with combustion turbine BACT for CO, catalytic oxidation and good combustor design are feasible methods of controlling VOC emissions. Both should be advanced for ranking in the top-down approach. VOC emissions are created through the same mechanisms as CO emissions, with the addition of trace amounts of VOC species in the natural gas fuel passing as uncombusted VOCs.

A.4.2.3Ranking and Evaluation of Remaining Alternatives

Catalytic oxidation system costs, energy impacts, and environmental impacts were previously reviewed and discussed under the BACT for CO section. Use of catalytic oxidation would consume extra fuel in the combustion turbine, and would create additional PM emissions. Assuming that the same catalytic oxidizer as designed for CO control would be used for VOC control, then total annual costs would be approximately $750,000 for the combustion turbine, as detailed in the BACT for CO section of this document. Accurate estimates for reduction in VOC emissions due to catalytic oxidation are not available for the Alstom Power GT10B combustion turbine. Prior to catalytic oxidation, VOC emissions from the combustion turbine have been guaranteed to be less than 10 ppmvd at 15% O_2, which is equal to approximately 9.45 lb/hr. Based on available information, VOC emissions reduction between 50% to 70% can be expected due to the use of catalytic oxidation. Conservatively assuming a 50% reduction, controlled VOC emissions are estimated to be 4.725 lb/hr. Based on 8,760 hours per year of operation for the combustion turbine, VOC emissions reduction are equal to approximately 20.696 tons per year. Thus, catalytic oxidation cost effectiveness for VOC reduction would be approximately $36,239 per ton. Because PGE has already decided that it will use oxidation catalyst for controlling CO emissions, the high cost per ton of VOC emissions reduction is immaterial.

The Alstom Power GT10B combustion turbine would use state of the art combustor design to minimize VOC emissions before they are further controlled using catalytic oxidation.

A.4.2.4Summary

Combustion turbine VOC emissions are created through the same mechanisms as CO emissions. Catalytic oxidation is a technically feasible method of controlling VOC emissions, but is clearly not cost effective, if the purpose was to control just the VOC emissions. The next most stringent VOC control technique is good combustor design. PGE has already selected catalytic oxidation for controlling CO emissions. That along with good combustor design is selected as the BACT for controlling VOC emissions from the Alstom Power GT10B combustion turbine. VOC emission limit of 4.725 lb/hr on a 24-hour average basis, is proposed as BACT for the Alstom Power GT10B combustion turbine.

A.5 BACT for PM and PM_{10}

A.5.1 Theoretical Formation and Control of PM and PM_{10}

Combustion of natural gas in the combustion turbines results in low level emissions of PM. Emissions of PM from natural gas combustion are normally negligible. These emissions are primarily a result of carryover of noncombustible trace elements present in the fuel. Particulate matter emissions can also result from dust particles present in inlet air, and are dependent on the efficiency of the filtration devices that clean the inlet air to the combustor. Particulate matter emissions in the form of hydrocarbons resulting from incomplete combustion can result from liquid or solid fuels, but are not a significant source from natural gas combustion. No feasible add-on control mechanisms exist for controlling these emissions.

A.5.2 Combustion Turbine BACT for PM and PM_{10}

A.5.2.1 Previous BACT Determinations

A database search of EPA's RBLC for natural gas-fired combustion turbine (SCC Code 20100201) projects from 1990 to present is summarized in Table A-6. For realistic comparison purposes, only the smaller size combustion turbine projects, i.e. ones that have a power output less than approximately 50 MW or a maximum heat input rating less than approximately 500 mmBtu/hr, have been listed in Table A-6. Pollution prevention, combustion control, and use of natural gas as fuel are the various control technologies that are listed in the database. It is difficult to compare and determine which emission limit represents the most stringent control because most of the PM and PM_{10} emission limits are in different units and there generally appears to be no correlation between the size of the combustion turbines, control technology used, and PM and PM_{10} emission limits.

A.5.2.2 Technical Feasibility and Ranking of Remaining Alternatives

As mentioned above, little can be done to limit PM emissions from natural gas combustion. In AP-42 Section 3.1, EPA acknowledges that "PM emissions are negligible with natural gas firing…". The New Source Performance Standards require no PM controls for gas turbines. Turbine manufacturer's guarantees of PM emissions are highly variable, and depend on the anticipated natural gas quality, ambient dust concentrations, and the amount of risk accepted by the manufacturer. Particulate matter emissions estimates are typically conservative due to the lack of feasible methods of control.

A.5.2.3 Summary

Pipeline quality natural gas will be the only fuel used for the Alstom Power GT10B combustion turbine and is accepted as BACT. The combustion turbine will emit no more than 1.0 pound per hour of PM or PM_{10} on a 24-hour average basis.

TABLE A-6
Recent PM and PM_{10} Limits for Smaller Size Combustion Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	Combustion Turbine Type	Combustion Turbine Rating	Fuel Used	BACT/LAER
2.5 lb/hr	Pollution Prevention, Primary Fuel is Natural Gas with Backup as Distillate Oil, Efficient Operation of the Combustion Turbine	03/12/1997	Mead Coated Board, Inc., Alabama	Combined Cycle	25 MW 568 mmBtu/hr	Natural Gas with Distillate Oil as Backup	BACT
25.8 lb/hr	Pollution Prevention, Fuel Spec: Natural Gas Fired	02/19/1992	Thermo Industries, Ltd., Colorado	-	246 mmBtu/hr	Natural Gas	Other
9.9 tons/yr	No Controls Feasible	-	Brush Cogeneration Partnership, Colorado	-	350 mmBtu/hr	-	Other
12.4 tons/yr	No Controls Feasible	-	Colorado Power Partnership, Colorado	-	385 mmBtu/hr	Natural Gas	Other
0.0065 lb/mmBtu for Natural Gas, 0.026 lb/mmBtu for Fuel Oil	Pollution Prevention, Combustion Control, Fuel Spec: Clean Fuel	11/20/1991	Lake Cogen Limited, Florida	-	42 MW	Natural Gas, Fuel Oil	BACT
5 lb/hr	Pollution Prevention, Good Combustion	12/28/1999	Orange Cogeneration LP, Florida	-	368.3 mmBtu/hr	Natural Gas	BACT
9 lb/hr for Natural Gas, 10 lb/hr for Fuel Oil	Pollution Prevention, Good Combustion Practices, Fuel Spec: Low Sulfur Fuel	12/21/1999	Kissimmee Utility Authority, Florida	Simple Cycle	40 MW 367 mmBtu/hr	Natural Gas, No. 2 Fuel Oil	BACT
0.006 lb/mmBtu	Pollution Prevention, Combustion Control	02/26/1990	Oneida Cogeneration Facility, New York	GE Frame 6	417 mmBtu/hr	Natural Gas	Other
None	Use of Natural Gas	05/30/2001	TransAlta Centralia Generation, LLC, Washington	GE LM6000 Sprint Combustion Turbine with HRSG	47 MW 466 mmBtu/hr	Natural Gas	Other
8 lb/hr	No Controls Feasible	04/22/1994	Fleetwood Cogeneration Associates, Pennsylvania	GE LM6000	360 mmBtu/hr	Natural Gas	BACT
0.05 gr/dscf	Pollution Prevention, Natural Gas	02/13/1998	Kuparuk Central Production Facility, Alaska	GE Frame 6, Model PG6551 (B)	38.9 MW	Natural Gas	BACT

Note: PM and PM_{10} concentration units are presented as specifically noted in the database. No corrections to inconsistencies were made.

A.6 BACT for SO_2

A.6.1 Theoretical Formation and Control of SO_2

Small quantities of sulfur are present in the natural gas, primarily due to the addition of mercaptans for odorizing natural gas. Sulfur present in natural gas is oxidized to sulfur dioxide (SO_2) during the combustion process in the combustion turbine. A fraction of the SO_2 can be further oxidized to sulfur trioxide (SO_3) during the combustion process due to the presence of an oxidation catalyst.

A.6.2 Previous BACT Determinations

A database search of EPA's RBLC for natural gas-fired combustion turbine (SCC Code 20100201) projects from 1990 to present is summarized in Table A-7. For realistic comparison purposes, only the smaller size combustion turbine projects, i.e. ones that have a power output less than approximately 50 MW or a maximum heat input rating less than approximately 500 mmBtu/hr, have been listed in Table A-7. Majority of the permits that have been issued for natural gas-fired equipment using internal combustion do not even include a BACT determination or emission limits for SO_2. For some permits that do include such determination or emission limitations, natural gas use or no controls are the only types of control technologies that are listed in the database for control of SO_2 emissions. Use of low-sulfur oil is listed as the control technology for combustion turbines that also use oil for combustion. BACT determination or SO_2 emission limits for such units are not listed in Table A-7.

A.6.3 Combustion Turbine BACT for SO_2

The Alstom Power GT10B combustion turbine at PGE – Beaver Plant would fire only pipeline quality natural gas. Use of pipeline quality natural gas has been demonstrated as being generally accepted as BACT for SO_2 emissions.

TABLE A-7
Recent SO_2 Limits for Smaller Size Combustion Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	Combustion Turbine Type	Combustion Turbine Rating	Fuel Used	BACT/LAER
1.5 lb/hr	No Controls Feasible	02/19/1992	Thermo Industries, Ltd., Colorado	-	246 mmBtu/hr	Natural Gas	Other
3.2 tons/yr	No Controls Feasible	-	Brush Cogeneration Partnership, Colorado	-	350 mmBtu/hr	-	Other
3.2 tons/yr	No Controls Feasible	-	Colorado Power Partnership, Colorado	-	385 mmBtu/hr	Natural Gas	Other
1.65 lb/hr (1-hr Average)	Use of Pipeline Quality Natural Gas	05/30/2001	TransAlta Centralia Generation, LLC, Washington	GE LM6000 Sprint Combustion Turbine with HRSG	47 MW 466 mmBtu/hr	Natural Gas	BACT
0.0026 lb/mmBtu	Pollution Prevention, Fuel Spec: Use of Natural Gas	06/09/1993	Newark Bay Cogeneration Partnership, L.P., New Jersey	-	617 mmBtu/hr	Natural Gas	BACT
11.3 lb/hr	Pollution Prevention, Fuel Spec: 0.1% Sulfur in Fuel	04/22/1994	Fleetwood Cogeneration Associates, Pennsylvania	GE LM6000	360 mmBtu/hr	Natural Gas	BACT
-	Pollution Prevention, Natural Gas Fuel is Limited to 200 ppmv H_2S	02/13/1998	Kuparuk Central Production Facility, Alaska	GE Frame 6, Model PG6551 (B)	38.9 MW	Natural Gas	BACT

Note: SO_2 concentration units are presented as specifically noted in the database. No corrections to inconsistencies were made.

APPENDIX B

State of Oregon
Department of Environmental Quality Memorandum

Date: 10 July 2002

To: Jim Broad through Audry O'Brien (NWR)

cc: File 05-0008

From: Philip Allen and Steve Aalbers through Gerry Preston

Subject: PGE Port Westward Power Generating Unit 8 Air Quality Analysis

1. Background

The following analysis is a modification of the earlier analysis of the Port Westward Generating Project, which was reviewed on September 30, 2001 with a following addendum (October 31, 2001). The Project is on land located near Clatskanie that PGE leases from the Port of St. Helens, and is adjacent to the existing PGE Beaver Generating Plant. Unit 8 was originally designed as a temporary peaking facility with all emissions less than the Significant Emission Rate (SERs). These less than-SER emissions were the result of a permit-imposed limit on operating hours. The permit process for Unit 8 began in February 2001, and in May 2001 the Beaver Title V permit was modified to allow for the operation of Unit 8. Because all emissions were less than the SERs, an air quality analysis of Unit 8 was not required at the time of the May 2001 permit action. Contemporaneous to this process, the long-term PGE Port Westward Generating Project began and an air permit application was submitted on May 14, 2001.

After Unit 8 began operation, and the Port Westward permitting was initiated, the electrical power shortage situation changed in the Northwest requiring a long-term need for Unit 8 operation. PGE approached DEQ on this subject and learned there would be a conflict regarding the PSD rules if both the Unit 8 and Port Westward projects operated together. If Unit 8 were to be operated as a permanent facility at emission rates greater than the SER, then the Unit 8 emissions must be included in the NSR requirements that were triggered by the Port Westward Project. As a result, Unit 8 must be incorporated into the Port Westward Project analysis.

The air quality analysis was performed by PGE.

2. Emissions: Stack Parameters and Operating Scenarios

This analysis modifies the original analysis (reviewed on September 30, 2001) by incorporating the increases in emissions from the addition of Unit 8, and some adjustments to the Port Westward emissions. All other elements in the analysis remain the same, and in the interest of brevity this review will address Unit 8 and the changes in total Port Westward emissions, and only briefly summarize parts of the September 30, 2001 review. Details of the earlier analysis can be found in that review.

Plant Operation. Beaver Plant Unit 8 is a simple cycle, natural gas-fired CTG which generates less than 25 megawatts of power, and is located at PGE's Beaver Plant near Clatskanie, Oregon. The unit has two air pollution controls: water injection to reduce nitrogen oxides (NOx) and a catalyst to reduce the carbon monoxide (CO). In addition, the CTG has dry low-NOx burners to initially reduce the NOx emissions in the combustion process. A continuous emission monitoring system (CEMS) has been installed on Beaver Plant Unit 8 to monitor NOx and CO emissions. Construction on Unit 8 was completed on July 18, 2001 when the unit initially began generating power. The natural gas pipeline fuel is sampled quarterly by plant staff and analyzed for total sulfur content to verify compliance with the NSPS standard for sulfur dioxide

(0.8% total sulfur in fuel).

Emissions. In Table 1, the Beaver Plant Unit 8 emissions are shown for full-year operation (8,760 hours/year), and then combined with Port Westward Project emissions to show total project emissions. The Port Westward Project Emissions are as given in DEQ's 30 September 2000 review and addendum of the original air quality analysis.

Table 1:
Total Emissions (Port Westward plus Beaver Plant Unit 8)

Pollutant	Unit 8 (1) Max (lb/hr)	Unit 8 tpy	Port Westward tpy	Total tpy
PM10	1.0	4.4	117	121
SO2	0.8	3.5	56	60
NOx	16.74	66.6 (2)	233	300
CO.	6.83 (3)	29.8	224	254
VOC	4.725 (4)	20.7	67.8	89

Notes:
1) All emissions are based on the CTG operation at 0 deg F ambient air temperature.
2) The average annual emission rate at 51 deg F is 15.2 lb/hr = 66.6 tpy = 1.915 g/s.
3) The original estimate by CTG manufacturer (Alstom) was that CO emissions would rise to between 70-200 ppm due to use of a NOx water injection control. Based on the CTG manufacturer guarantee, plus a 95% control efficiency for a CO catalyst control, this results in a controlled emission rate of 10 ppm or 6.8 lb/hr. This is still a conservative estimate since the actual emissions results monitored by the Unit 8 CEMS have shown CO results of less than 1 ppm.
4) Based on stated 50% to 70% control efficiency by CO catalyst manufacturer (ATS Express), a control efficiency of 50% was selected to provide the emissions rate of 4.725 lb/hr over a 24- hour average basis.

An analysis was done by PGE of the potential increases in emissions due to the startup or shutdown of Beaver Plant Unit 8. This analysis included the review of actual CEMS data during the operation of the unit from August through December 2001. It was found that for startup, Unit 8 takes approximately 8 minutes to ramp up to 100% load. For shutdown, Unit 8 takes only approximately 1 minute. The CO catalyst control is always operating during startup/shutdown. Therefore, the CO emissions will continue to be controlled during these events, and there is no change in CO emissions during startup or shutdown.

For the NOx emissions, the Unit 8 water injection control is not activated till the unit reaches 100% load. However, a review by PGE of CEMS data during Unit 8 startup and 100% load operation, showed that the short duration, and level of startup emissions, are not significant relative to the predicted maximum hourly NOx emission of 16.74 lb/hr (see Table 1 above) as used in the visibility analysis. For PSD modeling, the annual average NOx emissions of 15.2 lbs/hr, or 66.6 tpy, is used, and again the contribution from startup emissions is not significant.

Stack Parameters. In the previous analysis, the Port Westward Project emissions were modeled for three load conditions (50%, 75% and 100%), with and without duct burning, and three ambient temperatures (0°F, 51°F and 90°F). Since Beaver Plant Unit 8 operates only at 100% load, the most conservative ambient temperature (0°F) was selected for modeling this unit. The stack parameters for Beaver Plant Unit 8 and those for the Port Westward Project from the previous analysis are shown in Table 2.

Table 2:
Stack Parameters for Port Westward Project plus Unit 8

Stack Name	Stack ID	UTM East meters	UTM North meters	Elev meters	Stack Height meters	Stack Diameter meters	Stack Velocity m/s	Temp (K)
Combustion Turbine #1	STACK1	487033	5112791	5.2	61	5.2	23.6	357
Combustion Turbine #2	STACK2	487053	5112717	5.2	61	5.2	23.6	357
Fire Pump	FIREPUMP	487004	5112901	5.2	10.7	0.25	18.7	659
Cooling Cell 1	CT1	486847	5113876	5.2	13.7	9.8	7.8	283
Cooling Cell 2	CT2	486858	5113864	5.2	13.7	9.8	7.8	283
Cooling Cell 3	CT3	486870	5113852	5.2	13.7	9.8	7.8	283
Cooling Cell 4	CT4	486882	5113840	5.2	13.7	9.8	7.8	283
Cooling Cell 5	CT5	486893	5113829	5.2	13.7	9.8	7.8	283
Cooling Cell 6	CT6	486920	5113800	5.2	13.7	9.8	7.8	283
Cooling Cell 7	CT7	486931	5113789	5.2	13.7	9.8	7.8	283
Cooling Cell 8	CT8	486943	5113776	5.2	13.7	9.8	7.8	283
Cooling Cell 9	CT9	486954	5113765	5.2	13.7	9.8	7.8	283
Cooling Cell 10	CT10	486965	5113753	5.2	13.7	9.8	7.8	283
PGE 24MW	BVR8	486699	5113270	5	12	2.7	35.8	805

3. Class II Area Analysis: Parameters

The parameters and other factors used in this modification are the same as for the analysis of the Port Westward Project (see the 30 September 2001 review of that analysis for a full description).

Model. The dispersion model used was ISCST3, version 00101, which was the same model used in the original analysis

Landuse. Rural.

Plant Configuration. See previous review.

Building Downwash. Building structures were modeled using EPA BPIP, version 95086.

Competing Sources. DEQ provided the competing source parameter and emissions information

Background. The air quality data collected by Nucor Steel adjacent to the Beaver plant were used.

Receptor Grids. See previous review.

Meteorology.

Surface: Data collected by Nucor at a site adjacent to the plant for one full year (from May 1, 1993, through April 30, 1994).

Upper Air: Twice-daily mixing heights from the Salem NWS station.

The Class II PM_{10} NSR modeling analysis that was performed for the Port Westward Project does not need to be repeated for the addition of Unit 8, since that analysis included Unit 8 as a competing source, and its emissions are included in total modeled PM_{10} impacts. As a result, only those modeling runs for predicting maximum concentrations of NOx, CO and SO_2, from the original Port Westward Project analysis, are repeated to include the addition of Beaver Plant Unit 8.

In the Port Westward Project analysis, maximum impacts occurred while the turbines operated at 100% load with duct firing at 0°F ambient temperature. Therefore, the combined modeling of Port Westward Project plus Unit 8 addresses this 100% load case. The only exception in the previous modeling was for PM_{10}, where 50% load at 0°F ambient temperature produced the maximum 24-hour average impact. However, that Port Westward PM_{10} modeling required competing source modeling, which included Beaver Plant Unit 8 operating conservatively at 100% load all year long. This modeling also showed that the maximum Port Westward PM_{10} impacts were associated with operation at 100% load and 0°F ambient temperature. Therefore, the maximum PM_{10} impacts shown in the original report, and in Table 3 below, are the same and include modeling results for combining both Port Westward Project and Beaver Plant Unit 8 emissions

4. Class II Area Analysis: Results

The ISCST3 model results together with standard and guideline levels are shown in the following tables. Table 3 shows the updated results from the final analysis of the original Port Westward Project. Table 4 shows the model results for the expanded Port Westward Project that includes Unit 8 operating at full capacity (8760 hrs/year).

Table 3.
Results from Fine Grid Analysis for Criteria Pollutants (Updated for Turbine Startup/Shutdown Emissions)

		Maximum		Receptor			Operating Scenario				
Pollutant	Averaging Period	Impact ug/m3	SIL ug/m3	UTM East meters	UTM North meters	Elevation meters	% Load	Temp deg	Duct Burning	full ops hrs	starts hrs
NOx	Annual	**0.64**	1	486076	5106305	206.9	100	0F	with Duct	7439	1321
CO	1-Hour	424.27	2000	487076	5113705	0.1	All	All	All		
CO	8-Hour	**31.5**	500	486926	5113555	6.1	All	All	All		
SO2	3-Hour	9.82	25	483776	5113905	185	100	0F	with Duct		
SO2	24-Hour	1.53	5	489876	5111005	177.8	100	0F	with Duct		
SO2	Annual	0.16	1	486076	5106305	206.9	100	0F	with Duct		
PM10	24-Hour	3.46	1	485126	5114705	136.4	50	0F	without Duct		
PM10	Annual	0.34	0.2	486076	5106305	206.9	100	0F	with Duct		

Table 4.
Results from Fine Grid Analysis for Criteria Pollutants (Updated for Turbine Startup/Shutdown Emissions plus Unit 8)

		Maximum		Receptor			Operating Scenario				
Pollutant	Averaging Period	Impact ug/m3	SIL ug/m3	UTM East meters	UTM North meters	Elevation meters	% Load	Temp deg	Duct Burning	full ops hrs	starts hrs
NOx	Annual	**0.98**	1	486076	5106305	206.9	100	0F	with Duct	7439	1321
CO	1-Hour	424.3	2000	487076	5113705	0.1	All	All	All		
CO	8-Hour	**34.3**	500	486926	5113555	6.1	All	All	All		
SO2	3-Hour	**10.19**	25	483776	5113905	185	100	0F	with Duct		
SO2	24-Hour	**1.67**	5	489876	5111005	177.8	100	0F	with Duct		
SO2	Annual	**0.17**	1	486076	5106305	206.9	100	0F	with Duct		
PM10	24-Hour	3.46	1	485126	5114705	136.4	50	0F	without Duct		
PM10	Annual	0.34	0.2	486076	5106305	206.9	100	0F	with Duct		

The results show that the maximum impacts for NO_2, CO, and SO_2 are less than the significance levels, and no further analysis of near source impacts is necessary. Further analysis for PM_{10} was conducted including competing sources. (The competing source inventory is provided at the end of 30 September 2001 review.) The original Port Westward Project analysis for PM_{10} included Unit 8 emissions as a competing source, and the maximum PM_{10} impacts identified in that analysis remain as maximum impacts for this review in which Unit 8 is included as part of the Port Westward Project. For convenience those results are repeated in Table 5 and Table 6.

Table 5:
PGE Port Westward plus Unit 8: Analysis of Impacts Against Class II Ambient Air Quality Standards

Averaging Period	Maximum Impact ug/m3	UTM e m	UTM n m	Elevation m	(1) Background ug/m3	Total ug/m3	Primary NAAQS ug/m3	Secondary NAAQS ug/m3
Annual	6.79	485976	5106355	196.0	15.4	22.2	50	50
24-Hour	52.89	484826	5114305	153.7	49	101.9	150	150

Note: 1) Ambient data measured by Nucor at a location adjacent to the PGE site.

The results show that the projected PM_{10} impacts from the source (Port Westward plus Unit 8), together with competing sources and background, for both the Annual and 24-hr averages, are less than the NAAQS.

Impacts to visibility, vegetation, and soils were considered acceptable by comparison to the secondary ambient air quality standards, which were promulgated to protect public welfare including impacts to nonhuman health resources.

The PSD increment consumption for receptors above the SIL was evaluated. This evaluation included all nearby increment consuming sources with emissions increases since baseline. Sources with negative increment were modeled with zero emission rates. The results are shown in the following table.

Table 6:
PGE Port Westward plus Unit 8: Analysis of Impacts Against Class II PSD Increment

Averaging Period	Maximum Impact ug/m3	UTM e m	UTM n m	Elevation m	Class II PSD Increment ug/m3
Annual	0.69	485976	5106405	192.3	17
24-Hour	13.05	484776	5114255	149.9	30

The results show that the projected PM_{10} impacts from the source together with emissions from nearby increment consuming sources, for both the Annual and 24-hr averages, are less than the PSD Increment. The results of the Class II analysis show that impacts from the proposed source (Port Westward plus Unit 8) are less than the applicable Class II NAAQS and PSD Increment standards.

5. Class I Area Analysis: Parameters

As with the Class II analysis, this review modifies the original analysis (reviewed on September 30, 2001) by incorporating the increases in emissions from the addition of Unit 8, and some adjustments to the Port Westward emissions. All other elements in the analysis remain the same. A more detailed discussion of the earlier analysis can be found in that review.

Class I Areas. There are six Class I areas and a National Scenic Area within 200 km of the facility that were included in the analysis.

Table 7.
PGE Port Westward: Class I Areas within 200 km of facility

Class I Area	State	Distance km	Evaluated
Columbia River Gorge NSA	Oregon	98	Yes
Mt Rainer National Park	Washington	128	Yes
Mt Adams Wilderness	Washington	135	Yes
Mt Hood Wilderness	Oregon	143	Yes
Goat Rocks Wilderness	Washington	143	Yes
Olympic National Park	Washington	154	Yes
Mt Jefferson Wilderness	Oregon	190	Yes

Model. The long-range transport model used is CALPUFF version 5.4, and its associated pre and post-processors.

Modeling Domain. For this analysis, a Lambert Conic Conformal (LCC) projection was used for the coordinate system.

CALMET. Generation of windfields. See earlier review for settings.

Emissions for Class I Increment and Deposition. Subsequent to DEQ's 30 September 2001 review of the initial analysis, and changes proposed by DEQ to represent shutdown-standby-startup emissions, PGE responded with a request for a modification to DEQ's proposed steadystate operating conditions. PGE's modification resulted in marginally greater hours of operating with duct burning. As described in DEQ's addendum to the 30 September review, these changes only affected NO_x emissions.

Table 8.
PGE Port Westard plus Unit 8: Emissions rates used in Calpuff for Class I Increment

	SO2 lbs/hr	NOx lbs/hr	PM10 lbs/hr
3-hour Emission Rates			
2 CTGs	12.72	n/a	n/a
Fire-Water Pump	0.063	n/a	n/a
Unit 8	0.8	n/a	n/a
Total	13.58	n/a	n/a
Factor: add Unit 8	1.06	n/a	n/a
24-hour Emission Rates			
2 CTGs	12.72	n/a	26.8
Fire-Water Pump	0.0079	n/a	0.0015
Unit 8	0.8	n/a	1.0
Total	13.53	n/a	27.80
Factor: add Unit 8	1.06	n/a	1.04
Annual Emission Rates			
2 CTGs (addendum) (1)	12.2	53.3	26.8
2 CTGs (orig)	n/a	43.8	n/a
Fire-Water Pump	0.0002	0.0072	0.0004
Unit 8	0.8	16.74	1.0
Total	13.00	113.85	27.80
2 CTGs (orig)	n/a	43.80	n/a
Factor: Mods + Unit 8	1.07	1.30	1.04

note: 1) Original CTG NOx emissions were modified by PGE as an addendum, and total modification to original modeled PSD Increment is shown by the increase factor.

Table 8 shows the emission rates used for the Class I PSD Increment and deposition analysis, and includes: 1) the changes in NO_x emissions from the modification in duct-firing hours requested by PGE for Port Westward, 2) the addition of Unit 8, and 3) the correction factor used to adjust the previous modeled Class I impacts for both Increment and deposition.

Emissions for visibility modeling. The initial modeling for the visibility analysis did not consider the possible increase of NO_x, SO_2, and PM_{10} emissions during start ups. During discussions with PGE regarding the inclusion of startups in the 24-hour estimates, a DEQ email (2/26/02) stated that NO_x emissions from a cold start scenario gave the highest 24-hour emission rate. However warm and cold starts are necessarily preceded by standby periods of 8 and 48 hours, respectively, during which there are no emissions entering the Calpuff modeling domain. As a result, these warm and cold start emissions scenarios are not considered for the visibility analysis. The hot start scenario, with a short preceding standby or cool down period, is considered to contribute to visibility impairment. It was found that a combination of a hot start (over a period of 1.23 hrs) coupled with steady state emissions (over 22.77 hrs) gave a higher 24-hr average NO_x emission rate than the steady state alone (63.59 lbs/hr vs 42 lbs/hr, respectively). The maximum short term SO_2 and PM_{10} emissions over 24 hours remained at the steady state rate of 12.2 lbs/hr and 26.8, respectively. These calculations are shown in Table 9, and stack parameters in Table 10.

Table 9.
PGE Port Westward plus Unit 8: Maximum short-term NOx, SO2, and PM10 emissions for visibility analyses
All Steady state at 51 F

NOx	hrs	NOx lbs/event	Remaining Hrs in 24	Max Steady state lbs/hr	Remaining Steady state lbs	Total for 24 hours lbs	Starts + Steady St lbs/hr	PW Max lbs/hr	Unit 8 lbs/hr	PW plus Unit 8 Max lbs/hr	Emissions used in Initial Analysis lbs/hr	Adjustment factor
Hot Start	1.23	570	22.77	42	956.21	1526.21	**63.59**	**63.59**	16.74	80.33	44.06	1.82
Therefore, a 24 hr period that contains a 1.23 hr hot start and 22.77 hrs of 42 lbs/hr steady state gives max 24 hr emission rate of 63.59 lbs/hr.												
SO2												
Hot Start	1.23	8	22.77	**12.2**	277.76	285.76	11.91	12.20	0.80	13.00	12.73	1.02
Maximum SO2 emission rate over 24 hrs is under steady state conditions.												
PM10												
Hot Start	1.23	14	22.77	**26.8**	610.16	624.16	26.01	26.80	1.00	27.80	26.82	1.04

The adjustment factor shown in Table 9 is based on the ratio of the new emissions (Port Westward hot start plus Unit 8) ratioed to the emissions used in the original visibility modeling. This ratio is used to factor the original Calpuff visibility output to account for the increase in emissions.

Table 10.
PGE Port Westard: Stack Parameters used in Calpuff

	Stack Height m	Temp. K	Velocity m/s	Exit Velocity m/s	Diameter m
Combustion Turbine #1	60.96	356.5	23.6	5.18	5.18
Combustion Turbine #2	60.96	356.5	23.6	5.18	5.18
Fire-Water Pump	10.67	659.3	18.7	0.25	0.25

6. Class I Area Analysis: PSD Increment

The Calpuff output files were post-processed using the CALPOST and POSTUTIL programs.

Post Processor. CALPOST.

Results. Table 11 summarizes the predicted maximum NO_2, SO_2, and PM_{10} concentrations in each of the Class I areas. The maximum modeled impact values from the original Port Westward Project have been scaled to account for the addition of Unit 8 using the factors determined in Table 8. The predicted annual, 24-hr, and 3-hr average concentrations are well below the Class I SILs. The proposed emission rates are considered not to have consumed increment. Because the facility impacts would not be considered significant, no further analysis for PSD Increment and NAAQS is required for the Class I areas.

Table 11.
PGE Portwestward plus Unit 8: Class I Area PSD Increment Impacts

Pollutant	Avg Time	Class I Area Receiving Max Impact	Max PW Impact ug/m2	Unit 8 factor	Total Max Impact ug/m2	Class I SIL ug/m4	PSD Class I Increment ug/m3
NO2	Annual	Mt. Ranier NP	0.0007	1.3	0.0009	0.1	2.5
SO2	Annual	Mt. Adams	0.0003	1.07	0.0003	0.1	2
SO2	24-hour	Mt. Ranier NP	0.0076	1.06	0.0081	0.2	5
SO2	3-hour	Mt. Ranier NP	0.0251	1.06	0.0266	1	25
PM10	Annual	Mt. Hood	0.0012	1.04	0.0012	0.2	4
PM10	24-hour	Mt. Ranier NP	0.0163	1.04	0.0170	0.3	8

Note: 1) It is assumed that all NOx is in the form of NO2.

Class I Area Analysis: Visibility

The Class I visibility analysis for the addition of Unit 8, including an adjustment to reflect start up emissions for Port Westward, is based on the results of the original visibility analysis. In addition to total modeled extinction, those results were also reported as the extinctions of the individual particulate species. The revised total extinctions were developed in the following manner. The new total visibility emissions for SO_2, NO_x, and PM_{10} (including the modified hot start, and Unit 8) were ratioed to the original modeled emission rates. These three factors (SO_2, NO_x, and PM_{10}) were then applied to their respective extinction species taken from the Calpost output files for each of the Class I areas, and a new total extinction was calculated for each area. These new total extinction increases were then ratioed to the natural background values and a new Delta bext (as percentages) were derived for each Class I area.

Post Processor. CALPOST.

Species. Fine particulate (soil), sulfate, nitrate, elemental carbon, organic carbon.

Background. The seasonal natural background extinction coefficients for sulfate and nitrate were calculated from the speciated reference values for the Class I areas (*FLAG Report*).

Relative Humidity (RH). An hourly relative humidity (RH) adjustment was applied to observed and modeled sulfate and nitrate concentrations. RH was capped at a maximum value of 98 % (option 2 in CALPOST).

Results. Tables 12 and 13 show the predicted change in 24-hour extinction coefficients for each Class I Wilderness area. The original modeled values have been adjusted to reflect hot start emissions and the addition of Unit 8. The extinction budgets are predominantly influenced by the nitrates, which is in agreement with the relatively high NO_x emissions. The predicted changes in extinction as the result of the proposed facility emissions are less than the 5 percent criterion suggested by the FLMs in the FLAG Report, and Class I areas, and are acceptable.

Table 12.
PGE Port Westward plus Unit 8: Visibility impairment
Class I Information

Class I Area	Receptor Coordinate x (1) km	Receptor Coordinate y km	Highest Visibility Impairment Date
Mt Jefferson	-68	-132.083	5/6/1998
Mt Hood	-72	-70.66	4/23/1999
CRGNSA	-106.941	-41.103	8/29/1998
Mt Adams	-47.223	21.3	5/13/1998
Goat Rocks	-46.3	66.703	7/4/1998
Mt Rainier NP	-70.096	85.3	1/8/1999
Olympic NP	-174.425	169.3	10/30/1998

Note: 1) Lambert conformal coordinate system with a reference north latitude of 46 degrees, a reference west longitude of 121 degrees, standard parallels of 42.5 and 48 degrees north latitude, and standard meridian of 121 degrees west longitude.

Table 13.
PGE Port Westward plus Unit 8: Visibility impairment
Maximum Change to 24-hr Background Extinction

	Original Modeled Bext by Component					Factored Bext by Component							
Class I Area	bxSO4 (1/Mm)	bxNO3 (1/Mm)	bxOC (1/Mm)	bxEC (1/Mm)	bxPMF (1/Mm)	x 1.02 bxSO4 (1/Mm)	x 1.82 bxNO3 (1/Mm)	x 1.04 bxOC (1/Mm)	x 1.04 bxEC (1/Mm)	x 1.04 bxPMF (1/Mm)	Total Bext (1/Mm)	Back (1/Mm)	Delta Bext (%)
Mt Jefferson	0.009	0.034	0.007	0.017	0.004	0.009	0.062	0.007	0.018	0.004	0.100	16.177	0.62%
Mt Hood	0.027	0.135	0.009	0.020	0.005	0.028	0.246	0.009	0.021	0.005	0.309	18.42	1.68%
CRGNSA	0.009	0.074	0.039	0.090	0.020	0.009	0.135	0.041	0.094	0.021	0.299	29.819	1.00%
Mt Adams	0.031	0.149	0.009	0.021	0.005	0.032	0.271	0.009	0.022	0.005	0.339	22.05	1.54%
Goat Rocks	0.03	0.146	0.007	0.016	0.004	0.031	0.266	0.007	0.017	0.004	0.324	21.029	1.54%
Mt Rainier NP	0.017	0.222	0.011	0.026	0.006	0.017	0.404	0.011	0.027	0.006	0.466	23.412	1.99%
Olympic NP	0.009	0.204	0.012	0.029	0.006	0.009	0.371	0.012	0.030	0.006	0.429	18.38	2.34%

7. Class I Area Analysis: Deposition

Post Processors.

POSTUTIL. The CALPUFF wet and dry deposition files for SO_2, SO_4, NO_2, HNO_3, NH_4NO_3 and $(NH_4)_2SO_4$) were processed to calculate S and N deposition rates. The nitrogen from the ammonium was also included in the N deposition rate.

CALPOST. CALPOST was used to extract the S and N deposition rates for all receptors.

Background. For information on the source of background levels and criteria levels, see the 20 September 2001 review.

Results. The predicted nitrogen and sulfur deposition rates in the Class I areas are shown in the following table. These values have been scaled to account for the inclusion of Unit 8. The predicted nitrogen and sulfur deposition rates are well below the Significant Impact Level proposed by FLMs, and are several orders of

magnitude lower than the maximum load (IWAQM2). Thus, deposition impacts from the proposed emissions from the facility are not considered significant.

Table 14.
PGE Port Westward plus Unit 8: Total Wet Plus Dry Annual N and S Deposition

Class I Area	Receptor Coord x km	Receptor Coord y km	Receptor Modeled Deposition g/m2/s	Receptor Modeled Deposition kg/ha/yr	(1) Background kg/ha/yr	Total kg/ha/yr	Unit 8 factor	Total Deposition kg/ha/yr	Max Load kg/ha/yr	Significant Impact Level kg/ha/yr
Nitrogen Deposition										
Olympic NP	-174.425	169.300	5.26E-13	0.00017	2.0	2.0002	1.30	2.60	5	0.005
Mt. Rainier NP	-68.300	82.919	1.24E-12	0.00039	2.4	2.4004	1.30	3.12	5	0.005
Goat Rocks	-43.207	73.300	8.87E-13	0.00028	9.0	9.0003	1.30	11.70	5	0.005
Mt. Adams	-47.238	19.300	8.72E-13	0.00028	9.0	9.0003	1.30	11.70		0.005
CRGNSA	-106.941	-41.103	2.19E-12	0.00069		0.0007	1.30	0.00		
Mt. Hood	-72.000	-70.660	8.63E-13	0.00027	5.4	5.4003	1.30	7.02	5	0.005
Mt. Jefferson	-68.000	-132.083	3.59E-13	0.00011	1.8	1.8001	1.30	2.34	5	0.005
Sulfur Deposition										
Olympic NP	-174.425	169.300	4.16E-13	0.00013	5.6	5.6001	1.07	5.99	3	0.003
Mt. Rainier NP	-68.300	82.919	1.01E-12	0.00032	3.1	3.1003	1.07	3.32	3	0.003
Goat Rocks	-43.207	73.300	7.28E-13	0.00023	11.8	11.8002	1.07	12.63	3	0.003
Mt. Adams	-47.238	19.300	8.01E-13	0.00025	10.8	10.8003	1.07	11.56	3	0.003
CRGNSA	-106.941	-41.103	2.03E-12	0.00064		0.0006	1.07			
Mt. Hood	-72.000	-70.660	9.58E-13	0.00030	8.6	8.6003	1.07	9.20	3	0.003
Mt. Jefferson	-68.000	-132.083	3.94E-13	0.00012	4.0	4.0001	1.07	4.28	3	0.003

Note: 1) 2x highest annual wet deposition from the USFS Technical Report PNW-GTR-299 (May 1992).

8. Conclusions

The review of the air quality analysis of the PGE Port Westward Project, including Unit 8 operating at full capacity, using the emission rates, stack parameters, and unit locations provided in the analysis, or modified by PGE and DEQ during the review, show that impacts satisfy the following requirements:

1) NAAQS and PSD Increment for both Class II and Class I areas are satisfied.
2) Annual nitrogen and sulfur deposition are within the "significance" levels, and are acceptable.
3) Visibility impairment is less than the 5% criteria level for all Class I areas and the CRGNSA, and is acceptable.

The USFS as FLM had earlier commented that the air quality analysis for this source is acceptable, with the observation that this source together with other sources should be included in a cumulative impact analysis.

The air quality analysis as reviewed demonstrates that the facility will not have adverse impacts, and the air quality analysis is acceptable.

APPENDIX C

Oregon
Kate Brown, Governor

Department of Environmental Quality
Northwest Region
700 NE Multnomah Street, Suite 600
Portland, OR 97232
(503) 229-5263
FAX (503) 229-6945
TTY 711

2/11/16

Ms. Elysia Treanor
Portland General Electric Company
c/o Environmental Services Department
121 SW Salmon Street
Portland, OR 97204

RE: Pre-Enforcement Notice
Portland General Electric Company
PEN No. 2016-PEN-1366
Title V Permit No. 05-2520
Columbia County

Dear Ms. Treanor:

Portland General Electric owns and operates two power plants, known as Beaver Generating Plant and Port Westward I Generating, under Title V Permit No. 05-2520. On September 10, 2015, DEQ conducted a Title V Permit inspection at the Beaver & Port Westward I plants located at 80997 Kallunki Road, Clatskanie, OR 97016. During that inspection, several records were requested, including the July 2015 *Beaver Generating Plant Turbine 8 – Monthly Emissions & Operations Report.* Upon subsequent review of this data, several daily emission reports were also requested via email on October 20, 2015. This data included the *Beaver Generating Plant Turbine 8 – Daily Emissions & Operations Reports* for specific days in July, including July 3, 2015; July 7, 2015; July 9, 2015; July 15, 2015; July 19, 2015; July 20, 2015 and July 29, 2015, which were sent from PGE via email on October 30, 2015.

Based upon a review of the *Beaver Generating Plant Turbine 8 – Daily Emissions & Operations Reports* for July 7, 2015; July 9, 2015 and July 29, 2015, DEQ found four (4) BACT limit exceedences from consecutive hourly operation equal to 8 hours. PGE also reported four (4) additional BACT limit exceedences from this turbine after subsequent meetings and discussions between PGE and DEQ on the operation of this turbine. These eight (8) exceedences are shown below:

Date	Pollutant	8-hour rolling average (ppmvd @ 15% O_2)	Operating Hours
6/23/2015	NOx	18.3	15:00 – 22:00
	CO	13.8	
7/7/2015	CO	8.5	09:00 – 16:00
7/9/2015	CO	7.9	09:00 – 16:00
7/29/2015	NOx	17.8	13:00 – 20:00
	CO	9.0	
9/9/2015	CO	8.0	07:00 – 14:00
9/10/2015	CO	14.9	08:00 – 15:00

Based upon a review of the relevant data, DEQ has concluded that PGE is responsible for the following violations of Oregon environmental law:

VIOLATIONS:

(1) Title V Permit No. 05-2520 Condition No. 35, which states:

> "The permittee must not cause or allow the emissions of nitrogen oxides (NOX) from emission unit PTEU1 in excess of 17 ppmvd corrected to 15% oxygen, based on an 8-hour rolling average. Nitrogen oxides must be controlled by the use of Dry Low NOX combustion (DLN), water injection, and good combustion practices. Nitrogen oxides must be measured by CEMS. Water injection is not required during startup and shutdown. See Condition 64 for monitoring requirements."

(2) Title V Permit No. 05-2520 Condition No. 36, which states:

> "The permittee must not cause or allow the emissions of carbon monoxide from emission unit PTEU1 in excess of 5 ppmvd, corrected to 15% oxygen based on an 8-hour rolling average. Carbon monoxide must be controlled by catalytic oxidation, and good combustion practices. Carbon monoxide must be measured by CEMS. See Condition 65 for monitoring requirements."

This matter is being referred to DEQ's Office of Compliance and Enforcement for formal enforcement action. Formal enforcement action may result in assessment of civil penalties and/or a Department order. A formal enforcement action may include a civil penalty assessment for each day of violation. DEQ understands that PGE wishes to enter into a Mutual Agreement and Order (MAO) with DEQ in order to resolve the violations cited above; we look forward to drafting an MAO and aiding PGE in returning to compliance.

If you believe any of the facts in this Pre-Enforcement Notice are in error, you may provide written information to me at the address shown at the top of the letter. The Department will consider new information you submit and take appropriate action.

The Department endeavors to assist you in your compliance efforts. Should you have any questions about the content of this letter, feel free contact me in writing or by phone at 503-229-5425.

Sincerely,

Patty Jacobs
DEQ/Northwest Region Office

cc: Leah Feldon, OCE, DEQ
EPA Paul Koprowski

APPENDIX D

BEFORE THE ENVIRONMENTAL QUALITY COMMISSION

OF THE STATE OF OREGON

IN THE MATTER OF: PORTLAND GENERAL ELECTRIC COMPANY, an Oregon corporation.	)	MUTUAL AGREEMENT AND FINAL ORDER No. AQ/V-NWR-16-049

WHEREAS:

1. Portland General Electric Company (PGE) owns and operates the Beaver Generating Plant (Beaver) which is located at 80997 Kallunki Road near Clatskanie, Oregon. Beaver consists of 6 combined cycle combustion turbines and one 24 megawatt simple cycle combustion turbine referred to as Unit 8 as well as emission unit PTEU1. PGE operates the Beaver facility under Oregon Title V Operating Permit No. 05-2520 (Title V Permit).

2. Beaver is located in a designated attainment area for all regulated pollutants and is subject to DEQ's Prevention of Significant Deterioration (PSD) rules in OAR Chapter 340, Division 224.

3. On September 5, 2002, the Department of Environmental Quality (DEQ) issued PGE a PSD major modification (PSD Permit) for Beaver that included establishing Best Available Control Technology (BACT) limits for Unit 8 for nitrogen oxides (NOx) and carbon monoxide (CO) emissions.

4. The PSD Permit established the NOx BACT limit at 17 parts per million by volume, dry (ppmvd) corrected to 15% oxygen based on an 8-hour rolling average, and required the use of Dry-Low NOx combustion, water injection, good combustion practices and continuous emissions monitoring. Water injection was not required to be operated during startup or shutdown.

5. The PSD Permit established the CO BACT limit at 5 ppmvd corrected to 15% oxygen based on an 8-hour rolling average, and required the use of catalytic oxidation, good combustion practices and continuous emissions monitoring.

6. The NOx and CO BACT limits are incorporated into PGE's Title V Permit as Conditions 35 and 36 respectively.

7. Neither Condition 35 or 36 of the Title V Permit specifies how the 8-hour rolling averages are to be calculated, and neither permit condition expressly requires that the BACT limits be met during startup and shutdown.

8. Startup and shutdown emissions were accounted for when establishing the NOx and CO BACT limits in the PSD Permit, per the PSD application prepared by PGE dated April 2002.

9. The Review Reports accompanying the 2002 PSD Permit and Title V Permit expressly state that the NOx and CO BACT limits apply during startup and shutdown.

10. DEQ recognizes that it is currently not DEQ's policy or practice to apply BACT limits during the startup and shutdown of combustion turbines. DEQ further recognizes that the NOx and CO BACT conditions for Unit 8 should be clarified to specify how the 8-hour rolling averages are calculated.

11. When startup and shutdown emissions are included in determining compliance with the CO and NOx BACT limits and the 8-hour rolling average consists of 8 consecutive hours, there were 6 days during 2015 when the limits were exceeded for one or more rolling 8-hour period in violation of OAR 340-224-0070(2), ORS 468A.045(2), and Conditions 35 and/or 36 of the Title V Permit. These periods were not reported consistent with the requirements of OAR 340-214-0330 and 340-218-0050(3)(c)(B). If compliance were determined using non-consecutive operating hours, additional periods of noncompliance would have existed.

12. Based upon the interpretation that the Unit 8 NOx and CO BACT limits apply during periods of startup and shutdown, Unit 8 could continue to exceed its NOx and CO BACT limits unless and until those limits are clarified to specify that startup and shutdown emissions are not subject to the BACT limits.

13. PGE has voluntarily ceased operation of Unit 8 during the time period of discussions with DEQ as to the appropriate compliance demonstration methodology. It is important that Unit 8 be returned to service to provide cost-effective grid reliability.

14. DEQ and PGE recognize that the Environmental Quality Commission has the authority to impose a civil penalty and to issue an abatement order for violations of Oregon environmental law. Therefore, pursuant to ORS 183.417(3)(a) and (b), DEQ and PGE agree to settle the past violations referred to in Paragraphs 3 through 11 above and to resolve alleged potential ongoing violations as described in Paragraph 12 above, in advance, through this Mutual Agreement and Final Order (MAO).

15. By entering into this MAO, PGE neither admits nor denies the allegations related to or arising from any of the matters in this MAO.

NOW THEREFORE, it is stipulated and agreed that:

16. DEQ will modify both the PSD and Title V Permits as follows:

a. Define startup as 16 minutes from the commencement of fuel flow to the turbine;

b. Define shutdown as the 7 minutes immediately prior to ceasing fuel flow to the turbine;

c. Specify that compliance with the 8-hour rolling average is determined by averaging the emission rate during a unit operating hour with the emission rate during the previous 7 unit operating hours, whether consecutive or non-consecutive. This calculation does not include emissions data from any period of time where the unit is in startup or shutdown.

17. The Environmental Quality Commission shall issue a final order requiring that PGE:

a. Respond in a timely way to all information requests received from DEQ and necessary to DEQ in order to process the modification referenced in paragraph 16 above;

b. Determine the 8-hour rolling averages for purposes of determining compliance with the NOx and CO BACT limits using the most recent valid

unit operating hour of data and the prior 7 unit operating hours of valid data, exclusive of emissions during startup and shutdown as defined in this MAO.

c. For the duration of this MAO, submit a report no later than 30 days after the end of each calendar quarter identifying any periods of noncompliance with the limits, as determined consistent with Paragraph 17.b. This obligation does not affect the requirement under the Title V Permit to immediately report periods of excess emissions.

d. Submit semi-annual compliance certifications for Beaver as required by the Title V Permit. Compliance with the Unit 8 CO and NOx BACT limits is to be determined during the effective period of this MAO by calculating an 8-hour rolling average based on the most recent hour and the previous 7 operating hours, whether consecutive or not, and exclusive of data generated during startup and shutdown.

18. Requiring PGE to pay the following civil penalties:

a. A civil penalty in the amount of $21,600 for the alleged violations of DEQ's regulations described in Paragraphs 11 and 12 in the Recitals above.

b. The penalties in Paragraph 18(a) above are due within 60 days of the date this MAO is fully executed. Payment must be made by check or money order made payable to the "Oregon State Treasurer" and sent to: Business Office, Department of Environmental Quality, 811 SW Sixth Avenue, Portland, Oregon 97204. The total penalty amount may be reduced by the amount spent on one or more DEQ-approved Supplemental Environmental Projects (SEPs) if the SEP is approved by DEQ prior to the payment deadline. Such decrease cannot exceed $17,280. PGE must provide the documentation to DEQ specified in the SEP approval if PGE chooses to implement a SEP.

19. Requiring PGE, upon receipt of a written Penalty Demand Notice from DEQ, to pay $2,400 for each day that PGE is late in submitting a report required by Paragraph 17.

20. If any event occurs that is beyond PGE's reasonable control that causes or may cause a delay or deviation in performance of the requirements of this MAO, PGE must immediately notify DEQ verbally of the cause of delay or deviation and its anticipated duration, the measures that have been or will be taken to prevent or minimize the delay or deviation, and the timetable by which PGE proposes to carry out such measures. PGE must confirm in writing this information within five (5) working days of the onset of the event. It is PGE's responsibility in the written notification to demonstrate to DEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the reasonable control and despite due diligence of PGE. If PGE so demonstrates, DEQ will extend times of performance of related activities under this MAO as appropriate. Circumstances or events beyond PGE's control include, but are not limited to, acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or consultant's failure to provide timely reports will not be considered circumstances beyond PGE's reasonable control. However, delay in DEQ approval of documents due to no act or omission of PGE's will be considered circumstances beyond PGE's control.

21. Regarding the violations and potential violations set forth in Paragraphs 3 through 12 in the Recitals above, which are expressly settled herein, PGE hereby waives any and all of its rights to any and all notices, a contested case hearing, judicial review, and to service of a copy of the final order herein. DEQ reserves the right to enforce this order through appropriate administrative and judicial proceedings.

22. DEQ and PGE may amend the terms of this MAO by mutual written agreement.

23. PGE agrees that this MAO shall be binding on PGE and its respective successors, agents, and assigns. The undersigned representative of PGE certifies that he or she is fully authorized to execute and bind PGE to this MAO. No change in ownership or corporate or partnership status relating to the Facility will, in any way, alter PGE's obligation under this MAO, unless otherwise approved in writing by DEQ.

////

24. All reports, notices and other communications required under or relating to this MAO should be sent to: Patty Jacobs, DEQ Northwest Region Office, 700 NE Multnomah Street, Portland, OR 97232. Alternatively, communications can be directed via email to Jacobs.Patty@deq.state.or.us. The contact person for PGE is: Thomas Nilan, 121 SW Salmon Street, 3WTCBR05, Portland, OR 97204. Alternatively, communications can be directed via email to Tom.Nilan@pgn.com.

25. PGE acknowledges that it has actual notice of the contents and requirements of this MAO and that failure to fulfill any of the requirements hereof will constitute a violation of this MAO and will subject PGE to payment of civil penalties.

26. Any stipulated civil penalty imposed pursuant to Paragraph 19 is due upon written demand. Stipulated civil penalties must be paid by check or money order made payable to the "State Treasurer, State of Oregon" and sent to: Business Office, Department of Environmental Quality, 811 SW Sixth Avenue, Portland, Oregon 97204. Within twenty (20) days of receipt of a "Demand for Payment of Stipulated Civil Penalty" Notice from the Department, PGE may request a hearing to contest the Demand Notice. At any such hearing, the issue will be limited to PGE's compliance or noncompliance with this MAO. The amount of each stipulated civil penalty for each violation and/or day of violation is established in advance by this MAO and will not be a contestable issue.

27. DEQ may amend the compliance schedule and conditions in this MAO upon finding that such modification is necessary because of changed circumstances or to protect public health and the environment. DEQ must provide PGE a minimum of thirty (30) days written notice prior to issuing an amended order modifying any compliance schedules or conditions. If PGE contests the amended order, the applicable procedures for conduct of contested cases in such matters will apply.

28. This MAO will terminate at the time DEQ issues modified PSD and Title V Permits to PGE reflecting the changes discussed in Paragraph 16 above and PGE fully pays all

////

penalties and fees required by Paragraphs 18 and 19 above and completes all Supplemental Environmental Projects, if undertaken.

PORTLAND GENERAL ELECTRIC COMPANY

3-18-16
Date

Signature

JAMES F. LOBDELL
Name (print)

SVP FINANCE, CFO, TREASURER
Title (print)

FINAL ORDER

IT IS SO ORDERED:

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

March 18, 2016
Date

Sarah Wheeler for
Leah K. Feldon, Manager
Office of Compliance and Enforcement
on behalf of DEQ pursuant to OAR 340-012-0170
on behalf of the EQC pursuant to OAR 340-011-0505

APPENDIX E

Public Notice

Information Meeting: DEQ to Draft Air Quality Permit Revision for Portland General Electric

The purpose of this notice is to invite you to a meeting regarding a proposed Title V and Prevention of Significant Deterioration (PSD) Permit revision for Portland General Electric's PGE peaking turbine, known as emission unit PTEU1 (Beaver Plant Unit 8). This permit revision is a reopening to clarify calculation methods and correct a material mistake in the original Best Available Control Technology (BACT) limits for the peaking turbine PTEU1 (Unit 8). This permit revision will not allow any increase in emissions from this unit or the facility.

DEQ's Role

The Oregon Department of Environmental Quality (DEQ) is responsible for protecting and enhancing Oregon's water and air quality, for cleaning up spills and releases of hazardous materials, and for managing the proper disposal of hazardous and solid wastes. One way DEQ does this is by requiring permits for certain activities. DEQ issues permits to regulate the type and amount of air emissions at a regulated facility.

Meeting details

Date: Wednesday, July 20, 2016
Begins: 6 p.m.

Clatskanie Cultural Center
Birkenfeld Theater
75 S Nehalem Street
Clatskanie, OR

What will happen at this meeting?

DEQ staff will share information about the permit revision and what DEQ may include in the permit. You will have the opportunity to ask questions and provide input concerning the permit action. DEQ will consider any information gathered in the meeting in the drafting of the permit revision, but will not maintain an official record of the meeting and will not provide a written response to the comments.

Comments due:

Written comments due: 5 p.m., Friday July 22, 2016.

Where can I send comments?

NWR Permit Coordinator
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

Fax: 503-229-6945
Email: nwrarpermits@deq.state.or.us

Where can I get technical information?

Patty Jacobs, P.E., Environmental Engineer 3
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

Phone: 503-229-5425 or 800-452-4011
Fax: 503-229-6945
Email: Jacobs.Patty@deq.state.or.us

How can I review documents?

You can review the original Title V and PSD permit, the Pre-Enforcement Notice (PEN)and the Mutual Agreement and Final Order (MAO) at the DEQ office in Portland. For a review appointment, call Susan Curry at 503-229-6736.

About the facility

PGE operates fossil fuel-fired power plants under their Title V Permit 05-2520 and Standard ACDP 05-2606. These plants (Beaver, Port Westward I and Port Westward II) are located at 80997 Kallunki Road, Clatskanie, OR. The PTEU1 turbine subject of this permit revision is part of the Beaver power plant which is permitted to operate under their Title V Permit 05-2520. The operation of this equipment releases particulate matter (PM), carbon monoxide (CO), nitrogen oxide (NO_x), sulfur dioxide (SO_2), volatile organic compounds (VOC), hazardous air pollutants, and greenhouse gases (GHG) to the air.

What is proposed?

PGE obtained a permit for the construction of a small 24 MW peaking turbine (PTEU1) in 2001, which allowed the turbine to operate under the significant emission rates for criteria pollutants. In 2002, PGE submitted a PSD/Title V significant permit modification application to allow operation of the turbine at higher emission levels; which included a BACT analysis and an ambient air quality analysis. The BACT analysis included a thorough review of control technologies for NO_x, CO, SO_2, VOC and

DEQ

State of Oregon
Department of
Environmental
Quality

Northwest Region
700 NE Multnomah Street,
Ste 600
Portland, OR 97232
Phone: 503-229-5425
800-452-4011
Fax: 503-229-6945
Contact: Patty Jacobs
email:
Jacobs.patty@deq.state.or.us

www.oregon.gov/DEQ

DEQ is a leader in restoring, maintaining and enhancing the quality of Oregon's air, land and water.

DEQ provides documents electronically whenever possible in order to conserve resources and reduce costs.

If you received a hard copy of this notice, please consider receiving updates via e-mail instead. Send your request to: subscriptions@deq.state.or.us

Please include your full name and mailing address so that we can remove you from our print mailing list.

PM/PM_{10}. The turbine operates infrequently (Table 1), as it is a peaking unit used to provide additional power when needed, and rarely operates 8 consecutive hours each dispatch.

The BACT limits were established at 17 ppmvd @ 15% O_2 for NO_x and 5 ppmvd @ 15% O_2 for CO, both 8-hour rolling averages. These limits are the subject of this permit revision. The permit did not include instructions on how to calculate the rolling average for non-consecutive operation, and did not expressly require these limits to be met during startup and shutdown.

Upon inspection in September 2015, it was found that the turbine had exceeded the BACT limits on 8 occasions when the turbine operated longer than 8 consecutive hours. These events were discussed in a PEN dated Feb. 11, 2016 and resulted in a MAO dated March 18, 2016, in which PGE paid a civil penalty for violations and DEQ agreed to clarify the permit conditions. Per the agreement in the MAO, DEQ will define the startup and shutdown periods with respect to turbine fuel flow, will define the rolling average calculation method for non-consecutive operation, and remove startup and shutdown emissions from this calculation which are customarily not included in BACT limits. The numeric BACT limits will not change, and there are no emission increases in this permit revision.

Who might have an interest?

People who work, live, and recreate in the area.

What legal requirements apply?

Oregon Revised Statutes (ORS) 468A.040 and Oregon Administrative Rules (OAR) Chapter 340 Division 216 and 218 give DEQ the authority to issue permits. OAR Chapter 340 Divisions 200 through 268 contains all pertinent rules that govern the air quality program.

How does DEQ determine what requirements go in the permit?

Various federal and state regulations apply to a facility depending on the type of industry, the type and amount of pollutants emitted, and the location of the facility. All applicable regulations must be contained in the permit, including the appropriate recordkeeping, monitoring, and reporting requirements to ensure compliance with these regulations.

What happens next?

Following the meeting, DEQ will draft the proposed permit revision. DEQ will send a hearing notice requesting formal oral and written comments concerning the proposed draft permit revision and review report.

DEQ will review and consider all comments about the proposed permit revision received during the comment period. During the comment period, DEQ will schedule a public hearing. An additional public notice will be published to advertise the public hearing.

Accessibility information

DEQ is committed to accommodating people with disabilities. Please notify DEQ of any special physical or language accommodations or if you need information in large print, Braille or another format.
To make these arrangements, contact 503-229-5696 or toll free in Oregon at 800-452-4011; fax to 503-229-6762; or email: mailto:mdeqinfo@deq.state.or.us.

People with hearing impairments may call DEQ's TTY number, 711.

Table 1
Annual Operational Hours for PTEU1

Year	PTEU1 (Unit 8) Hours	Year	PTEU1 (Unit 8) Hours
2001	691	2009	125
2002	164	2010	3.75
2003	2.6	2011	6.2
2004	7.3	2012	11.6
2005	23.2	2013	182
2006	45.5	2014	75
2007	52.7	2015	323
2008	11		