DEPARTMENT OF ECOLOGY
State of Washington

TECHNICAL SUPPORT DOCUMENT FOR PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT

PERMIT NO: PSD-11-05

Puget Sound Energy
Fredonia Power Generating Station

Prepared by

Air Quality Program
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Olympia, Washington

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EXECUTIVE SUMMARY

Puget Sound Energy (PSE) proposes to expand the Fredonia Generating Station (FGS) located at 13085 Ball Road near Mt. Vernon, Washington, by adding one or two simple cycle combustion turbines. The proposed project will provide up to approximately 181–207 megawatts (MW) of additional generating capacity to meet future PSE system needs. The new combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra-low sulfur diesel (ULSD) fuel oil.

The Washington State Department of Ecology (Ecology) received the Prevention of Significant Deterioration (PSD) application for the project on February 23, 2011. Additional information was received on July 7, August 3, October 31, 2011, and February 14, 2012. Ecology determined the application to be complete on November 22, 2011. PSE submitted a final revised PSD modification and Notice of Construction (NOC) permit application (revision 3) dated June 7, 2012, which included all the revisions noted above in one package.

PSE requests approval to construct one of the following four simple cycle combustion turbine options:

1. One (1) General Electric (GE) 7FA.05 frame turbine or a similar model, rated at approximately 207 MW.
2. One (1) GE 7FA.04 frame turbine or a similar model, rated at approximately 181 MW.
3. One (1) Siemens SGT6-5000F4 frame turbine or a similar model, rated at approximately 197 MW.
4. Two (2) 100 MW GE LMS100 high-efficiency aeroderivative turbines or similar models, with a combined rating of approximately 200 MW.

Ecology is allowing PSE to select the actual unit(s) to be installed after permit issuance. Ecology has included the four options in the permit. Only one option may be chosen and built. Air pollution control will include oxidation catalyst systems for the control of carbon monoxide (CO) and efficient combustion of inherently low polluting fuels. The chosen turbine option will use natural gas with limited firing of ULSD to control emissions of particulate matter (PM) and sulfuric acid mist (H_2SO_4).

The project also includes the installation of one (1) 600 kilowatt (kW) diesel-fired emergency standby generator, and eight (8) new and two (2) replacement insulated circuit breakers. Each circuit breaker will contain up to 201 pounds (lb) of a sulfur hexafluoride (SF_6) dielectric.

The proposed project emissions for PM, PM less than 10 micrometers (μm) in diameter (PM_{10}), PM less than 2.5 μm in diameter ($PM_{2.5}$), H_2SO_4, and greenhouse gases (GHG) are above the PSD major modification thresholds for all four turbine options. The CO emissions from the Siemens SGT6-5000F4 option (Option 3 above) are also above the PSD major modification threshold. Therefore, a full technical review of the project for these NSR pollutants, including a Best Available Control Technology (BACT) analysis, and the project's effect on National Ambient Air Quality Standards (NAAQS), PSD increments, visibility, soils and vegetation, is required and discussed in this Technical Support Document (TSD).

The emissions of other air pollutants not subjected to PSD review will be covered in the Northwest Clean Air Agency (NWCAA) NOC approval for this project.

1. INTRODUCTION

1.1. The Permitting Process

1.1.1. The PSD Process

PSD permitting requirements in Washington State are established in Title 40, Code of Federal Regulations (CFR) § 52.21; Washington Administrative Code (WAC) 173-400-700 through 750; and the agreement for the delegation of the federal PSD regulations by the United States Environmental Protection Agency (EPA) to Ecology, dated November 17, 2011.

Federal and state rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent significant adverse environmental impact from emissions into the atmosphere by a proposed new major source or major modification to an existing major source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on visibility, soils, and vegetation. PSD rules also require the utilization of BACT for certain new or modified emission units, which is the most effective air pollution control equipment and procedures that are determined to be available after considering environmental, economic, and energy factors.

The PSD rules must be addressed when a company is adding a new emission unit or modifying an existing emission unit in an attainment or unclassifiable area. PSD rules apply to pollutants for which the area is classified as attainment or unclassifiable with the NAAQS. PSD rules are designed to keep an area with "good" air quality in compliance with the NAAQS. The distinctive requirements of PSD are BACT, air quality analysis (allowable increments and comparison with the NAAQS), and analysis of impacts of the project on visibility, vegetation, and soil.

1.1.2. The NOC Process

PSE Fredonia Expansion Project is subject to NOC permitting requirements under state of Washington regulations Chapters 173-400 and 173-460. The NWCAA is the permitting authority for all air emission regulatory requirements not included in PSD permitting program. This includes the new source review (NSR) permitting of criteria pollutants that are not PSD-applicable, air toxics issues under federal MACT and state 173-460 WAC, and Title V permitting requirements. The procedure for issuing a NOC permit was established in Chapter 70.94 RCW.

WAC 173-400-110 NSR outlines the procedures for permitting criteria pollutants. These procedures are further refined in WAC 173-400-113 (requirements for new sources located in attainment or unclassifiable areas).

WAC 173-460-040 NSR supplements the requirements contained in Chapter 173-400 WAC by adding additional requirements for sources of toxic air pollutants (TAPs).

1.1.3. Federal Regulations Summary

This permit may not contain all the requirements included in the following summary. However, after the Title V and Acid Rain permits are issued, each of the following regulations will be addressed:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards (NSPS): Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	40 CFR 60, Subpart IIII
NSPS: Standards of Performance for Stationary Combustion Turbines	40 CFR 60, Subpart KKKK
NSPS Performance Specifications	40 CFR 60, Appendix B
NSPS Quality Assurance Procedures	40 CFR 60, Appendix F
Acid Rain Program	40 CFR 72
Sulfur Dioxide Allowance System	40 CFR 73
Continuous Emission Monitoring	40 CFR 75
Mandatory Greenhouse Gas Reporting	40 CFR 98

1.1.4. State Regulations Summary

This permit may not contain all the requirements included in the following summary. However, after the NOC, Title V, and Acid Rain permits are issued (by NWCAA), each of the following regulations will be addressed:

General Regulations for Air Pollution Sources	Chapter 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Carbon Dioxide Mitigation Program	Chapter 173-407 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

1.2. Site and Project Description

1.2.1. Site Description

The FGS facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington (see Figure 1). The site is on the south side of Ovenell Road, southwest of the Skagit Regional Bayview Airport, and approximately 2.5 miles inland of Padilla Bay. The proposed project is not expected to increase the current footprint acreage of the site, which is approximately 40 acres.

The terrain surrounding the facility is essentially flat. The elevation of the facility is approximately 50 feet above mean sea level (MSL).

The FGS facility is located in a Class II area that is designated as "attainment or unclassifiable" for the purpose of PSD permitting.

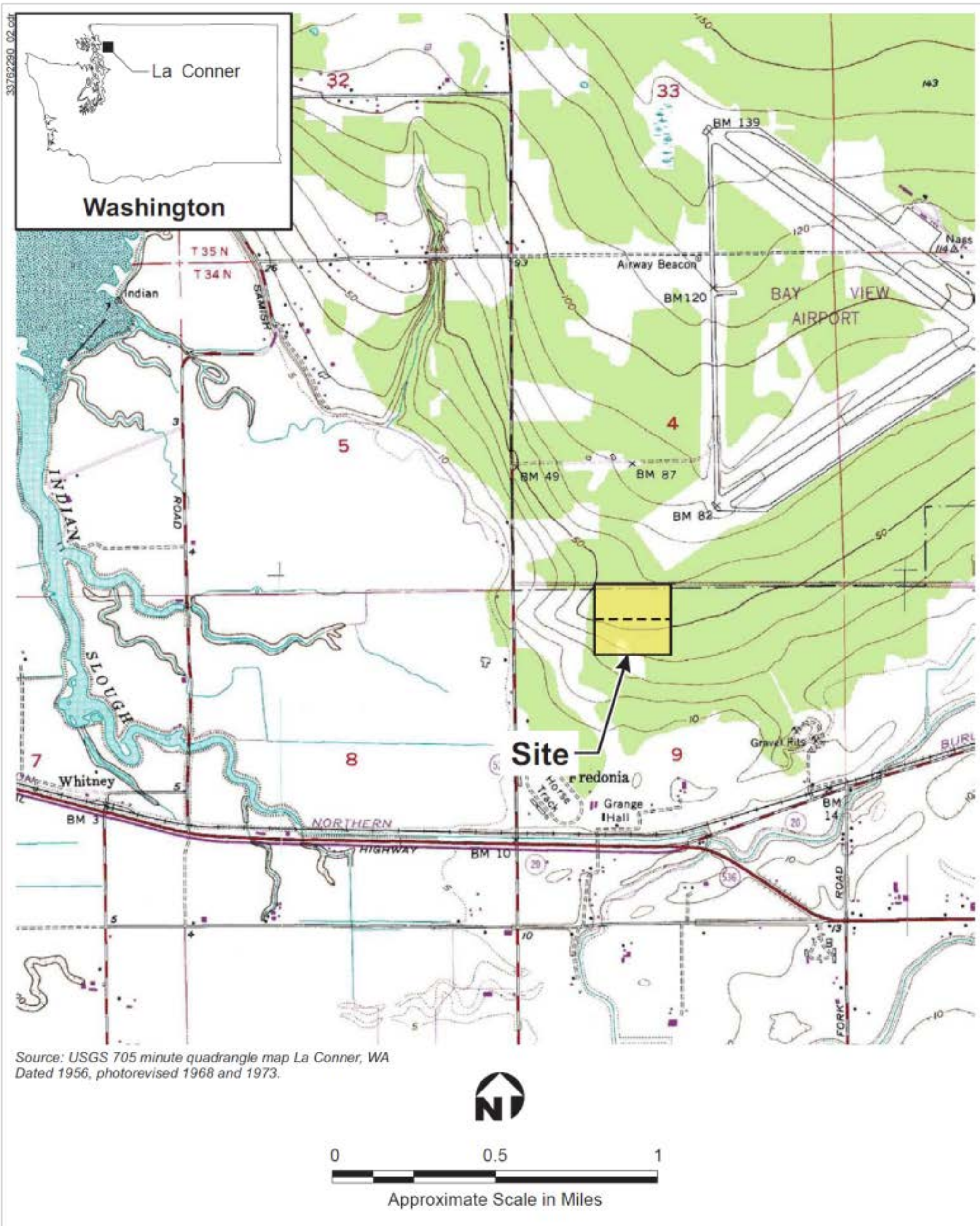

Figure 1. The FGS facility location map

(Source: PSE's PSD application 2nd revision, received July 7, 2011)

1.2.2. Project Description

PSE owns and operates the FGS facility. The existing FGS facility consists of two Westinghouse W501D simple cycle combustion generators, and two Pratt & Whitney Model FT-8 Twin Pac simple cycle combustion turbines. All four turbines are permitted to use either natural gas or distillate fuel. Natural gas is normally used, and distillate fuel is infrequently used as a backup fuel. The Westinghouse turbines (Units 1and 2) have a base load rating of 104 MW each. The Pratt & Whitney turbines (Units 3 and 4) have a base load rating of 54 MW each.

The project will utilize either one (1) or two (2) combustion turbines operating in simple cycle peaking mode. PSE proposes to interconnect the new unit(s) to the adjacent FGS substation, which is the nearest connection point to PSE's electrical grid. The purpose of the new generating unit(s) will be to provide additional power generation capacity (totaling approximately 181-207 MW, depending on the unit(s) selected after permit issuance) to help meet future PSE system needs using locally available fuels. No physical change or changes in method of operation will occur to the existing FGS units.

The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ULSD (0.0015% sulfur) No. 2 distillate fuel oil. Natural gas will be delivered to the site by the adjacent transmission pipeline owned by Cascade Natural Gas. ULSD is planned as backup fuel, and will be stored on-site in an existing 100,000-barrel tank. Backup fuel oil will be used to continue serving PSE's electrical load when natural gas supply is curtailed by the pipeline supply company, or is not reasonably available to be received at the facility. Historically this has happened, but it is a rare occurrence.

Overall, the project includes the following emission sources:

- One (1) or two (2) simple cycle combustion turbine generators
- Emergency generator
- Switchyard circuit breakers

1.2.2.1. Simple Cycle Combustion Turbine Options

The proposed project includes installation of one or two of the following high-efficiency simple cycle combustion turbine(s):

- One (1) GE 7FA.05 frame turbine or a similar model, approximately 207 MW.
- One (1) GE 7FA.04 frame turbine or a similar model, approximately 181 MW.
- One (1) Siemens SGT6-5000F4 frame turbine or a similar model, approximately 197 MW.
- Two (2) 100 MW GE LMS100 aeroderivative turbines or similar models, totaling approximately 200 MW.

Any proposed turbine option will have a combination of gas turbine combustion controls, selective catalytic reduction (SCR), and an oxidation catalyst installed to minimize emissions from the project.

PSE Fredonia has proposed to restrict annual fuel usage to reduce potential annual emissions from each unit. All their calculations based on hours are for the purpose of analysis only. The permit conditions are based on equivalent fuel usage, which will be explained in Section 2.2.1.4.

Annual operating hours (excluding start-up and shutdown (SUSD) hours) are assumed to be 2,280 hours per year (hr/yr) for frame turbines (GE 7FA.05, GE 7FA.04 and Siemens SGT6-5000F4) and 2,880 hr/yr for each of the two GE LMS100 aeroderivative turbines. ULSD will only be fired for a maximum of 336 hours per turbine in any consecutive 12 months, subject to the restrictions on annual operating hours.

In order to minimize emissions during SUSD, the number of starts per year per unit will be limited to 144 starts on natural gas and 14 starts on backup distillate for frame turbines (GE7FA.05, GE 7FA.04 and Siemens SGT6-5000F4), and to 240 starts on natural gas and 14 starts on backup distillate for each of the two GE LMS100.

1.2.2.2. Emergency Generator

The project includes one nominal 600 kW diesel standby generator (Caterpillar C18, or equivalent) to supply the new units' critical electrical loads in the event power could not be back fed from either the site's 230 kV or 115 kV transmission systems. The turbine(s) would be supplied with a 125 voltage direct current (VDC) battery bank to supply a critical 120 voltage alternating current (VAC) Essential Power Bus through an inverter, or directly from a 125 VDC Essential Power Bus. Examples of devices needing Essential Power from one or both of these sources would be the facility's Distributed Control System (DCS), protective relays and a direct current (DC) driven emergency lube oil pump.

In the event of a transmission system failure and blackout of the facility, the 125 VDC and 120 VAC Essential Power Buses could be kept energized for a period of time from the 125 VDC battery bank. However, the turbine units have the potential to expend the battery's power quickly since they have large, heavy components, such as rotor bearings, that require lubrication during turbine spin down (and while at rest to prevent seizing). The lubrication oil flow is provided by large electrically driven lubricating pumps. To prevent damage to these components during a transmission system failure, an emergency generator is needed to provide power to back up the batteries.

Manufacturer required reliability testing and maintenance operations for the emergency generator are expected to occur one hour per week, or 52 hours per year. It is estimated that emergency use will not exceed 223 hours, for a total of up to 275 hours of emergency generator operation annually.

1.2.2.3. Switchyard

The project's proposed new 230 kV switchyard will include eight new circuit breakers. The new circuit breakers will be filled with sulfur hexafluoride (SF_6), which is a gaseous dielectric fluid commonly used in power system circuit breakers. In addition to these eight circuit breakers for the new equipment, there will be two other new circuit breakers installed to replace some existing circuit breakers. A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage. Therefore, these 10 circuit breakers are included in emission calculations because of their predicted GHG emissions. Although specific circuit breaker models have not been identified, PSE expects that Mitsubishi 200-SFMT-40E or 200-SFMT-63F breakers (or similar) will be used.

2. PSD APPLICABILITY REVIEW

2.1. Overview and Permitting History

The existing facility is a major PSD stationary source per 40 CFR § 52.21(b) (1) (i), and operates under Permit No. PSD-01-04, issued by Ecology on July 18, 2003, and Permit No. X82-09 issued by EPA Region 10 on August 23, 1982, and amended on October 24, 1995. Under WAC 173-400-720 through 750, a project proposed at an existing major stationary source is subject to PSD review if the project either is a "major modification" to an existing "major stationary source," or is a major stationary source unto itself.

Unless otherwise exempted by applicable regulation, a change to an existing major stationary source is a major modification if the change results in both a significant emissions increase and a significant net emissions increase at the source. "Significant emissions increase" means that the emissions increase for any regulated PSD pollutant is greater than the PSD Significant Emission Rate (SER) threshold for that regulated pollutant.

The proposed FGS Expansion Project will require a PSD permit if both the project's emissions increase and the net contemporaneous emissions increase caused by the project exceed any PSD SERs of any NSR pollutant, including GHGs. The proposed simple cycle generating units to be located at the Fredonia site are new units. In accordance with the requirements of 40 CFR 52.21(a) (2), these emission increases associated with the new units is based on their potential to emit (PTE). Also, as addressed in the regulation, their baseline actual emissions are zero.

2.2. Emissions Calculation

The maximum capacity was examined by PSE for each of the emission units based on worst-case operating scenarios and emission calculations details are presented below, by following three air emission source types:

- Simple cycle combustion turbine generator(s), for which four equipment options are being considered by PSE:

  - One (1) GE 7FA.05 frame turbine or a similar model.
  - One (1) GE 7FA.04 frame turbine or a similar model.
  - One (1) Siemens SGT6-5000F4 frame turbine or a similar model.
  - Two (2) GE LMS100 aeroderivative turbines or a similar model.
- A 600 kW emergency generator (Caterpillar with Model C18 ATAAC Tier 2 engine (approximately 890 brake horsepower (bhp)), or similar make and model).
- Substation breakers containing SF_6.

2.2.1. Simple Cycle Combustion Turbine Generator(s)

2.2.1.1. Standard Peaking Mode Emissions

The combustion turbine manufacturers provided emission rate data for all criteria pollutants (except lead, whose emission factor is from EPA's "Compilation of Air Pollutant Emission Factors," commonly referred to as AP-42) during normal operation for three different ambient temperatures (7°F, 51°F, and 88°F). These temperatures are representative of the range of expected conditions at the PSE Fredonia facility.

As a peaking facility, the combustion turbines to be installed at this project are capable of extended operation at a broad load range as follows:

a. GE 7FA.05 option: 50 to 100 percent load when fired on either natural gas or ULSD.
b. GE 7FA.04 option: 50 to 100 percent load when fired on either natural gas or ULSD.
c. Siemens SGT6-5000F4 option: 60 to 100 percent load when fired on natural gas and 70 to 100 percent load when fired on ULSD.
d. GE LMS100 option: 30 to 100 percent load when fired on natural gas and 75 to 100 percent load when fired on ULSD.

"Normal operation" has been defined as all operating modes within the above load ranges, for which the permit limits can be achieved using gas turbine combustion controls, SCR, and an oxidation catalyst. Under normal operating conditions, all four of the potential combustion turbines will emit between 2.5 and 5 parts per million (ppm) nitrogen oxides (NO_X) and between 4 and 12 ppm CO (after the BACT determination, PSE accepted Ecology's request to lower CO concentration to 8 ppm from 12 ppm. Section 3.4 discusses the CO BACT analysis), depending on the turbine and fuel used.

Potential annual emissions for the new unit(s) are based on worst-case operating scenarios estimated by PSE from forecast load requirements; an ambient temperature, pressure, and relative humidity of 51°F, 14.68 psia and 75%, respectively; a maximum annual average natural gas sulfur content of 2.25 gr/100 scf;[1] and a maximum ULSD sulfur content of 15 ppmw. On a pollutant-by-pollutant basis, worst-case maximum operation on other loads other than 100% is included in the annual emission estimates *only if* pollutant emissions (on a lb/hr basis) under mixed loads are higher than emissions under full load. In addition, the worst-case maximum of 336 hr/yr (consecutive or nonconsecutive) firing on backup ULSD is included in the annual emission estimates *only if* pollutant emissions (on a lb/hr basis) on ULSD are higher than emissions on natural gas. Table 1 shows emission rates due to normal operation of the combustion turbines.

The potential emissions from each turbine must also incorporate any emissions during SUSD operation. Section 2.2.1.2 discusses SUSD emissions, and Section 2.2.1.3 provides a summary of estimated potential pollutant emissions from the combustion turbine taking into account standard peaking and SUSD operation.

[1] For the pipeline sulfur content, seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA, were analyzed. The maximum 365-day rolling average was 1.10 gr/100 dscf (June 2009). Because an upward trend was observed in data for 2009 and preceding years, PSE assumed a worst-case future concentration of 2.00 gr/100 dscf for the Williams Northwest Pipeline to achieve a margin of safety for the Project's emission compliance. On top of that, 0.25 gr/100 dscf was added to account for worst-case odorant addition by local natural gas utility, Cascade Natural Gas, for a total of 2.25 gr/100 dscf for annual emission calculations.

Table 1. Estimated Maximum Emissions From Turbine(s), Excluding SUSD

Pollutant	Fuel	GE 7FA.05		GE 7FA.04		Siemens SGT6-5000F4		GE LMS100	
		lb/hr	tpy[3]	lb/hr	tpy[3]	lb/hr	tpy[3]	lb/hr	tpy[3]
NO_X	NG	19.40	26.27	16.80	22.88	19.70	25.67	16.20	27.20
	ULSD	44.10		39.00		38.80		33.80	
CO	NG	18.60	25.19	15.60	21.08	8.44	15.80[4]	12.40	18.43
	ULSD	42.30		35.20		45.20[4]		10.00	
VOC	NG	3.70	5.16	2.90	4.08	2.70	3.72	4.60	8.12
	ULSD	9.30		7.50		6.50		13.20	
$PM/PM_{10}/PM_{2.5}$	NG	36.00	41.46	36.80	42.22	26.70	31.68	27.20	43.84
	ULSD	38.50		38.40		34.10		53.40	
SO_2	NG	4.99	5.69	4.37	4.98	4.47	5.10	4.22	6.09
	ULSD	1.26		1.12		0.98		1.00	
H_2SO_4	NG	13.34	15.21	11.66	13.29	13.92	15.87	11.30	16.28
	ULSD	3.36		3.01		3.04		2.56	
Pb	NG	0	0.0053	0	0.0047	0	0.0045	0	0.0042
	ULSD	0.03		0.03		0.03		0.02	
CO_2	NG	246,140	301,048	215,297	264,485	243,583	289,816	208,389	313,752
	ULSD	367,860		328,669		315,797		284,399	
CH_4 as CO_2e[1]	3.43E-04 lb/MMBtu	2,124 MMBtu/hr	1	1,858 MMBtu/hr	1	2,102 MMBtu/hr	1	899 MMBtu/hr	1
N_2O as CO_2e[1]	8.12E-01 lb/MMBtu		1,966		1,720		1,946		2,103
GHG (as CO_2e)[2]	---	---	303,015	---	266,206	---	291,763	---	315,855

[1] The emission factors for CH_4 and N_2O are based on a review of PSE's reports to the NWCAA, Southwest Clean Air Agency (SWCAA), and Ecology regarding compliance with Chapter 173-407 WAC, "Carbon dioxide mitigation program for fossil-fueled thermal electric generating facilities," and related source test results. Values are for natural gas use only; EPA's AP-42 emission factors for these pollutants show non-detects for distillate use. Therefore, maximum potential emissions are based on natural gas use only. The values include the conversion to CO_2e using the individual Global Warming Potential (GWP) factors for each pollutant. GHG as CO_2e = emission factor (lb/MMBtu) × Fuel Use (MMBtu/hr) × Annual Maximum Operating Hours (hr)

[2] GHGs (as CO_2e) = CO_2 + N_2O as CO_2e + CH_4 as CO_2e

[3] PTE calculations: (a) If emission rates firing with ULS (ER ULSD) > emission rates firing with natural gas (ER NG):
PTE = ER NG x (Annual Max Op. Hr-Max Op. Hr on ULSD) + ER ULSD x Max Op. Hr on ULSD
(b) If ER ULSD < ER NG: PTE = ER NG x Annual Max Op. Hr

[4] A new CO mass rate under the 8 ppm BACT CO limit (Section 3.4) is equal to 30.1 lb/hr and corresponding annual CO emission is equal to 13.27 tpy.

2.2.1.2. SUSD Emissions

A simple cycle combustion turbine does not have a steam cycle like a combined cycle turbine. Therefore, a simple cycle combustion turbine does not have cool or cold water, and boiler tubing to heat as part of the start-up sequence. Accordingly, start-up duration and quantity of emissions during start-up are unrelated to when the last shutdown occurred. The duration of SUSD for a combustion turbine in a simple cycle mode is relatively short because it is mostly related to bringing the turbine rotors up to speed, lighting the turbine burners, bringing the SCR and oxidation catalysts up to their minimum operating temperatures, and synchronizing the electric generator to the grid. As such, only one start-up duration is defined for each proposed turbine option for this project. Data was provided by each of the turbine vendors to quantify emissions during a start-up/shutdown event and its duration.

Since emissions from combustion turbines can be significantly higher during SUSD than during normal operation, they can represent a relatively substantial portion of the proposed project’s total PTE, and hence need to be accounted. During start-up, the turbines cannot initially operate in lean pre-mix mode, which results in higher emissions of some pollutants. A similar transition from lean pre-mix combustion to standard combustion occurs during shutdown, though the time involved is considerably shorter. In addition, the SCR catalyst is not effective until it reaches a minimum temperature of about 500°F. Even though an oxidation catalyst actually begins to reduce emission of CO as soon as the equipment is started, its rate of destruction is highly related with operating temperature. To account for this potential increase in emissions, a worst-case maximum number of SUSD on both natural gas and ULSD are included in the annual emission estimates for all pollutants.

Table 2 summarizes SUSD emissions and duration for each turbine. Potential lead (Pb) emissions during SUSD are not included in this table because they are less than 0.001 tons per year (tpy) for all options. Potential emissions of CH_4 and N_2O (GHG) during SUSD are also not included in Table 2 because emissions of those pollutants during SUSD are extremely low compared to standard operation. However, this contribution to the overall CO_2e is included in Table 3.

The number of start-ups and associated shutdowns per year per unit is limited to 144 of natural gas and 14 of backup distillate for frame turbines (GE 7FA.05, GE 7FA.04, and Siemens SGT6-5000F4), and to 240 of natural gas and 14 of backup distillate for each of the two GE LMS100 turbines.

Table 2. Baseline Actual Emissions (TPY)										
Options	SU/SD	Fuel	Duration (min)	Pollutant Emitted (lb/event/unit)						
				NO_X	CO	VOC	PM/ PM_{10}/ $PM_{2.5}$	CO_2	SO_2	H_2SO_4
GE 7FA.05	SU	Gas	30	31.5	209.6	5.9	9.2	69,717	10.4	5.8
		Oil	30	145.7	332.1	8.6	17	109,132	1.1	1.0
	SD	Gas	19	16	189	4.3	5.8	30,885	4.6	2.6
		Oil	17	79	196	6	9.6	44,157	0.4	0.4
	Annual Emission (tpy)			***5.0***	***32.4***	***0.8***	***1.3***	***8,316***	***1.1***	***0.6***
GE 7FA.04	SU	Gas	30	43.1	106.4	6.5	6	70,823	10.1	8.0
		Oil	30	168.1	140.1	5	17.4	108,102	1.1	1.0
	SD	Gas	14	31	90	4.8	4.4	28,819	4.2	3.2
		Oil	14	107	95	2	8.4	44,110	0.4	0.4
	Annual Emission (tpy)			***7.3***	***15.8***	***0.9***	***0.9***	***8,240***	***1.0***	***0.8***
Siemens SGT6-5000F4	SU	Gas	35	92.4	1,347	154.2	4.8	81,663	11.0	7.2
		Oil	38	146.2	1,462	162.2	15.6	99,757	1.0	1.0
	SD	Gas	17	45	443	50	2.4	41,460	5.4	3.6
		Oil	19	90	709	76	10	61,518	0.7	0.6
	Annual Emission (tpy)			***11.5***	***144.1***	***16.4***	***0.7***	***9,994***	***1.2***	***0.8***
GE LMS100 (2 units)	SU	Gas	30	34.5	49	1.0	3.3	43,546	6.5	3.7
		Oil	30	59.9	39.6	3.7	14.3	58,849	0.6	0.5
	SD	Gas	8	3.4	1.8	0.03	1.0	4,621	0.7	0.4
		Oil	8	5.7	1.7	0.06	4.7	5,555	0.05	0.05
	Annual Emission (tpy)[a]			***10***	***12.8***	***0.3***	***1.3***	***12,462***	***1.7***	***1.7***

[a] Annual SUSD emission estimate includes emissions from two (2) GE LMS100 turbines.

2.2.1.3. Overall PTE of the New Combustion Turbines

Table 3 summarizes the annual PTE from all four turbine options for each pollutant, including SUSD emissions.

Table 3. Estimated Maximum Annual Emissions From Turbine(s), Including SUSD				
Pollutant (tpy)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100
NO_X	31.3	30.1	37.2	36.3
CO	57.6	36.9	159.9[a]	30.6
VOC	6.0	4.9	20.1	8.4
$PM/PM_{10}/PM_{2.5}$	42.7	43.1	32.4	44.9
CO_2	309,364	272,725	299,810	325,312
GHGs (as CO_2e)	311,382	274,496	301,819	327,577
SO_2	6.8	6.0	6.3	7.8
H_2SO_4	15.8	14.1	16.7	17.3
Pb	0.0054	0.0048	0.0046	0.0042

[a] Under the 8 ppm BACT CO limit (Section 3.4), new annual CO emissions for the Siemens turbine option are equal to 157.4 tpy assuming there are no emission reductions during SUSD when firing distillate.

2.2.1.4. Maximum Fuel Uses

All emission calculations for any turbine option are based on hours of operation (standard peaking mode operations, start-ups, and shutdowns) for the purpose of analysis only. PSE and Ecology find it desirable to limit the fuel usage instead of the hours of operation because it offers flexibility a peaking facility needs. Annual fuel uses are estimated and summarized in Table 4.

Potential maximum annual fuel uses for the new unit(s) during standard peaking mode are based on full load equivalent turbine hours at an ambient temperature, pressure and relative humidity of 51°F, 14.68 psia and 75%, respectively; a maximum annual average natural gas sulfur content of 2.25 gr/100 scf;[2] and a maximum ULSD sulfur content of 15 ppmw. Potential maximum annual fuel uses for the new unit(s) during SUSD are based on fuel uses per SUSD event, and the number of SUSDs per year per fuel type allowed.

Table 4. Estimated Maximum Annual Fuel Uses From Turbine(s), Including SUSD

Options	Full Load Hourly Fuel Use During Standard Peaking Mode (MMBtu/hr)		SUSD Fuel Use (MMBtu/SUSD)		Maximum Annual Fuel Use (MMBtu/yr)	
	Gas	Oil	Gas	Oil	Gas & Oil	Oil[b]
GE 7FA.05	2124	2252	864	938		
Annual (MMBtu/yr)		4,886,181[a]	124,348	13,136	**5,023,664**	**769,664**
GE 7FA.04	1858	2012	856	932		
Annual (MMBtu/yr)		4,288,120[a]	123,195	13,043	**4,424,358**	**688,973**
Siemens SGT6-5000F4	2102	1933	1057	987		
Annual (MMBtu/yr)		4,793,111[a]	152,277	13,820	**4,959,209**	**663,277**
GE LMS100 (per unit)	899	870	415	394		
Annual (MMBtu/yr)[c]		5,179,684[a]	199,258	11,038	**5,389,979**	**595,924**

[a] Annual Fuel Use During Standard Peaking Mode (AF_SPM):
  i. If full load hourly fuel use firing with ULSD (FF_ULSD)>full load hourly fuel use with natural gas (FF_NG).
  ii. If FF_ULSD ≤ FF_NG: AF_SPM = FF_NG x Annual Max Op. Hr

[b] Maximum Annual Fuel Use for oil: FF_ULSD x Max Op. Hr on ULSD + total SUSD fuel use on ULSD

[c] Two units combined. In addition, according to Chapter 80.80.010 RCW and WAC 173-407-130, natural gas and ULSD shall only be fired for a maximum of 4,726,461 MMBtu per unit per year, subject to the annual fuel use restriction. This estimation is based on one unit operated at full load condition for 60% of a full year.

[2] For the pipeline sulfur content, seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA, were analyzed. The maximum 365-day rolling average was 1.10 gr/100 dscf (June 2009). Because an upward trend was observed in data for 2009 and preceding years, PSE assumed a worst-case future concentration of 2.00 gr/100 dscf for the Williams Northwest Pipeline to achieve a margin of safety for the Project's emission compliance. On top of that, 0.25 gr/100 dscf was added to account for worst-case odorant addition by local natural gas utility, Cascade Natural Gas, for a total of 2.25 gr/100 dscf for annual emission calculations.

2.2.2. Emergency Generator

Potential emissions were estimated based on maximum hours of testing/maintenance, emergency use, and emission factors either from EPA's "Compilation of Air Pollutant Emission Factors," commonly referred to as AP-42, or California Air Resources Board (CARB)'s Tier 2 Certified Diesel Generator Sheet.

Overall, testing and maintenance operations for the emergency generator are expected to occur one hour per week, or 52 hours per year. It is estimated that emergency use will not exceed 223 hours per year, for a total of up to 275 hours of emergency generator operation annually. Table 5 shows the maximum annual emissions for the emergency generator. Potential H_2SO_4 emissions from the emergency generator are not included in this table because they are very little (even if assuming 10% of SO_2 emissions are converted to SO_3, the annual H_2SO_4 emissions are far less than 0.001 tpy in this case).

Table 5. Estimated Annual Emissions from the Emergency Generator

Pollutant	Emission Factor		Annual Emission
	g/hp-hr	lb/hp-hr	tpy
NO_x[1]	4.32		1.05
CO[1]	0.6		0.15
VOC[1]	0.01		0.0024
$PM/PM_{10}/PM_{2.5}$[1]	0.06		0.015
CO_2[2]		1.16	128.28
CH_4[2]		6.35E-05	0.15 as CO_2e[3]
SO_2[2]		1.21E-05	0.0013

[1] NO_X, CO, VOC (HC), and PM emission factors from CARB Tier 2 Certified Diesel Generator sheet (Executive Order U-R-001-0380-1, New Off-Road Compression-Ignition Engines (August 30, 2010).
[2] CO_2, CH_4, and SO_2 emission factors from AP-42, Table 3.4.1.
[3] CH_4 GWP of 21 from 40 CFR 98, subpart A, Table A-1.

2.2.3. Substation Circuit Breakers Containing SF_6

A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage. There are no other air pollutants emitted from the substation. The rate of leakage is conservatively assumed to be 0.5% per year based on a review of losses from PSE's existing SF_6 circuit breakers. The quantity of SF_6 in each circuit breaker is based on equipment specifications. Because specific breakers have not yet been chosen for this project, the equipment option with the highest volume of SF_6 has been assumed for the emission calculations.

The breaker emissions are used in the GHG analyses, applying the 100-year SF_6 GWP of 23,900 to convert SF_6 emissions to carbon dioxide equivalents (CO_2e). Table 6 shows annual CO_2e emissions from proposed substation breakers.

Table 6. Estimated Annual Emissions From Substation Breakers

# of Breakers	SF_6 Amount (lb/breaker)	Leak Rate	SF_6 Leakage Amount (lb/yr)	SF_6 GWP	Annual CO_2e Emissions (tpy)
10	201	0.5%	10.05	23900	120.10

2.2.4. Toxic Emissions

The PSE Fredonia Project will emit federally listed noncriteria pollutants and hazardous air pollutants (HAPs) primarily as a result of incomplete combustion. The non-criteria pollutants include both federal HAPs as defined by EPA in Title III of the 1990 Clean Air Act Amendments and PSD regulated non-criteria pollutants. Emission rates have not been estimated for several PSD regulated pollutants, including asbestos, fluorides, vinyl chloride, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and radionuclides, because none of these PSD pollutants are expected to be emitted from the project.

PSE Fredonia estimated individual HAP annual maximum emission from the project (including the emergency generator), and found the total potential HAP emissions are 4.5 tpy for the GE 7FA.05 turbine; 3.9 tpy for the GE 7FA.04 turbine; 4.3 tpy for the Siemens SGT6 turbine; and 4.5 tpy for GE LMS100 turbines. These results are all well below the major HAP threshold of 25 tpy of total HAPs (or individual major HAP threshold of 10 tpy). Therefore, the project will be a minor source of HAP emissions.

PSE Fredonia also estimated individual TAP (according to the WAC 173-460-150) maximum emission rate (for the respective averaging period) from the proposed project, and compared each to Washington State’s small quantity emission rates (SQERs) and acceptable source impact levels (ASILs). Their impacts are evaluated as part of the ambient air quality analysis of the application.

Toxic emissions are not regulated by the PSD program, and will be regulated by NWCAA in the NOC permit they issue.

2.3. Overall Project Emissions Increase

The overall project emissions increase on a pollutant-to-pollutant basis is the sum of each pollutant PTE from each individual emission unit, as summarized in Table 7.

Table 7. Summary of PTE (TPY) and Comparison to PSD SER						
Pollutant	**GE 7FA.05**	**GE 7FA.04**	**Siemens SGT6-5000F4**	**GE LMS100**	**SER**	**PSD Review Required?**
NO_X	32	31	38	37	40	NO
CO	58	37	**160**[a]	31	100	YES for SGT6
VOC	6	5	20	8	40	NO
PM	**43**	**43**	**32**	**45**	25	YES for all
PM_{10}	**43**	**43**	**32**	**45**	15	YES for all
$PM_{2.5}$	**43**	**43**	**32**	**45**	10	YES for all
CO_2e	**311,631**	**274,744**	**302,067**	**327,826**	75,000	YES for all
SO_2	7	6	6	8	40	NO
H_2SO_4	**16**	**14**	**17**	**17**	7	YES for all
Pb	0.020	0.019	0.019	0.019	0.6	NO

[a] Under the 8 ppm BACT CO limit (section 3.4), new annual CO emissions are rounded to 157 tpy assuming there are no emission reductions during SUSD when firing distillate.

As shown in the emission summary above, potential emissions from the expansion project will exceed the PSD SERs for all turbine options for PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG. Potential emissions are also expected to exceed the SER for CO for the Siemens SGT6-5000F4 option. These pollutants are subject to full PSD review, consisting of the following:

- Determination of BACT
- Air quality impact analysis
- Evaluation of source-related impacts on growth, soils, vegetation, and visibility
- Evaluation of Class I area impacts

2.4. New Source Performance Standard (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP)

2.4.1. NSPS

NSPS have been established by EPA to limit air pollutant emissions from certain categories of new and modified stationary sources. Stationary gas turbines are regulated under 40 CFR Part 60, Subpart KKKK. The enforcement of this NSPS has been delegated to Ecology, and was adopted by reference in WAC 173-400-115.

In general, local emission limitation rules or BACT requirements are far more restrictive than the NSPS requirements. For example, although this project is not subject to PSD review for NO_X, the anticipated controlled NO_X emission rate from any of the project's natural gas-fired turbine options is less than 0.13 lb of NO_X per MW-hr, which will be well below the Subpart KKKK requirement of 0.39 lb of NO_X per MW-hr.

Similarly, the projected maximum SO_2 emissions from any of the gas turbine options will be about 0.05 lb of SO_2 per MW-hr, which is substantially less than the Subpart KKKK requirement of 0.58 lb of SO_2 per MW-hr. NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas as the primary fuel for the gas turbine generator(s). Emissions and fuel monitoring will be performed to demonstrate compliance with the requirements of BACT, NSPS, acid rain, and other regulatory requirements.

The use of ULSD as backup fuel also meets these requirements. There are no NSPS requirements for other air pollutants in Subpart KKKK.

40 CFR Part 60, Subpart IIII applies to the proposed emergency generator. Engine manufacturers are required to certify engines to prescribed NO_X, PM, CO, and VOC emission standards, and operators are required to follow manufacturer's operation and maintenance instructions. Subpart IIII also limits emergency engines to 100 hr/yr of nonemergency operation (i.e., maintenance and testing). The proposed engine for the project will be a certified unit, and the PSD application has been prepared with the assumption of a maximum of 52 hr/yr of nonemergency use.

2.4.2. NESHAP

EPA has issued a Maximum Achievable Control Technology (MACT) standard for gas-fired combustion turbines that are major HAP sources or are located at a major HAP source. However, on August 18, 2004, the EPA stayed the effective date of the MACT standard for lean pre-mix and diffusion flame gas-fired turbines until such time that these two subcategories could be deleted from the MACT standard. Since the proposed project on its own is a minor HAP source and any of the turbines allowed to be used are lean pre-mix turbines, there are currently no MACT standards applicable to the project.

3. BACT

3.1. Definitions and Policy Concerning BACT

All new major sources or major modifications are required to utilize BACT for those new and modified emission units that will experience an increase in emissions as a result of the project. BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost-effectiveness, economic, energy, environmental, and other impacts (40 CFR § 52.21(b)(12)).

Federal guidance requires each PSD permit applicant to implement a "top-down" BACT analysis process for each new or physically or operationally changed emissions unit. Ecology has adopted the top-down BACT process for its BACT determinations. This top-down BACT analysis process consists of five basic steps described below:[3]

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

If the applicant proposes to implement the most effective or “top” available control strategy, step 4 is not necessary.

As shown above, the "top-down" BACT process starts by considering all available emission control technologies, and ranks them for further evaluation from most effective to least effective technically available control technology. The most effective emission reduction technology is then evaluated for economic feasibility. If the technology is proven infeasible based on economics, energy or other environmental considerations, then the next most stringent level of reduction is considered. The most stringent level of emissions control that is not determined to be technically and economically infeasible is selected as BACT. While the permitting agency makes the final BACT decision, the burden is on the applicant to prove why the most stringent level of control should not be used.

In the case of the PSE Fredonia Expansion Project, PSD BACT is triggered for:

- $PM/PM_{10}/PM_{2.5}$ for each of the four proposed gas turbine options.
- H_2SO_4 mist for each of the four proposed gas turbine options.
- CO for the Siemens turbine option only.
- GHG for each of the four proposed gas turbine options.

PSE Fredonia’s BACT analysis focuses on recent relevant BACT determinations to identify the top current control levels achieved in practice. Three data sources were reviewed by PSE to identify relevant BACT determinations for simple cycle gas turbines in the past five years (2006–July 2011):

[3] See EPA’s *Draft New Source Review Workshop Manual*, 1990; and PSD and Title V Permitting Guidance for Greenhouse Gases <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>.

- EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- California Air Resources Board BACT Clearinghouse
- Information from California Energy Commission power plant sitting cases, including local air quality management district findings

Because BACT determinations generally become increasingly stringent as emission control technology and operating experience improve over time, only projects that were approved since January 2006 were included in this analysis.

In addition to reviewing the permit application and supporting documentation, Ecology performed independent review of the above data sources and other web resources, for the period January 1, 2006, through December 1, 2011. As necessary, Ecology contacted various permit agencies to obtain more information on issued and proposed permits.

3.2. BACT for PM, PM_{10}, and $PM_{2.5}$ Turbines

The objective of this analysis was to determine BACT for PM, PM_{10} and $PM_{2.5}$ emissions from any of four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD with total annual operation based on the maximum amount of fuel uses and types, summarized in Table 4.

PM emissions from combustion turbines are a combination of filterable and condensable particulate. Filterable PM is primarily formed from impurities contained in the fuels and incomplete combustion. Condensable particulate emissions are attributable primarily to the formation of secondary particulate from condensation of volatilized solid materials, unburned hydrocarbon, and the conversion of sulfates and nitrates in the exhaust stream after it has been vented from the stack into the atmosphere.

PM, PM_{10} and $PM_{2.5}$ are analyzed together because virtually all of the PM emitted from the turbines will be 2.5 micrometers (formerly called microns) or smaller, and referred to collectively as PM in this analysis.

3.2.1. Control Technology Review

The applicant submitted a full top-down BACT analysis for PM/PM_{10}/$PM_{2.5}$. In brief, available control technology options for PM emissions from the turbine are as follows:

Good combustion practices

Good combustion will ensure proper air/fuel mixing to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack.

Clean-burning fuels

The use of clean-burning fuels that have low ash and sulfur content, such as natural gas, will result in minimal formation of PM during combustion.

Dry-low NO_X combustor

The use of a dry-low NO_X (DLN) combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable PM. DLN combustors are in wide use on utility scale natural gas fired turbines.

Electrostatic precipitators

Electrostatic precipitators are used on solid fuel boilers and incinerators to remove PM from the exhaust. Electrostatic precipitators use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particles into collection hoppers.

Baghouses

Baghouses are used to collect PM by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags that are periodically shaken to release the particulates into hoppers.

Among all above control technologies, using natural gas exclusively as the fuel for the PSE Fredonia Project is not technically feasible because the nature of this project as a peaking facility. Dual-fuel simple cycle turbines represent the optimal method of generating power to meet peak demand. The use of ULSD as a backup fuel provides reliability during periods when there is high demand for natural gas, and usage of natural gas is curtailed at the Fredonia facility by the retail gas utility, or by the interstate pipeline owner. PSE Fredonia proposes to use natural gas whenever it is reasonably available, and ULSD will be used during what are expected to be very infrequent periods when natural gas is not reasonably available at the facility.

With respect to the add-on controls discussed above (i.e., electrostatic precipitators and baghouses), the EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive.[4] When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) or Subpart KKKK (2006) did not impose a particulate emission standard. No example of add-on type particulate control for natural gas fueled

[4] "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production," California Air Resources Board, <http://www.arb.ca.gov/energy/powerpl/appcfin.pdf>.

combustion turbines or similar natural gas combustion sources could be found in the EPA's RBLC, or from suppliers of control equipment.

The small particulate size and low particulate emission level, along with the lack of any example of add-on particulate controls, and lack of vendor performance guarantees led PSE Fredonia to propose that the primary use of natural gas with limited firing of ULSD and good combustion practices are BACT for all particulates emitted from the simple cycle combustion turbine.

3.2.2. Determination of Applicable PM BACT Emission Limitation

Using the above proposal that the primary use of natural gas with limited firing of ULSD and good combustion practices are BACT, the emission rates are largely determined by the amount of fuel burned and the amount of sulfur in the fuel. In this area of western Washington, our natural gas is from Canada. Long-term monitoring records of the total sulfur content of the gas imported from Canada shows this gas generally has higher sulfur content compared with the rest of country, and especially the gas sent to Washington and Oregon from Wyoming. PSE Fredonia analyzed seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, Washington. The maximum 365-day rolling average was 1.10 grains of sulfur/100 standard cubic feet (gr/100 scf) of natural gas (June 2009). The highest 99th percentile daily sulfur concentration measured at Sumas during the 7-year period is 3.23 gr/100 scf, plus an additional 0.25 gr/100 scf allowance for worst-case odorant addition by Cascade Natural Gas. In addition, an upward trend was observed in data for 2009, and proceeding years. While in California, the pipeline natural gas typically contains much less than one gr/100 dscf sulfur. For example, both the Marsh Landing and Panoche Energy Center permits limit natural gas sulfur to one gr/100 dscf in California.

As a result, unlike other pollutants' emission limits, it is impractical to compare the proposed PM emission limits with PM emission limits and performance data from simple cycle combustion turbines in other regions. Instead, the past BACT PM limits for other simple cycle turbines issued in Washington State are compared and listed in Table 8 to evaluate if the proposed PM emission limit satisfies the BACT requirement. Please note that the smaller size turbines will have lower mass emission rates in terms of pounds per hour. As a result, in order to provide a meaningful comparison with the proposed project, all emission limits are converted to lb/MMBtu input based on their approximate sizes. Another important factor to consider when comparing permit limits from different simple cycle combustion turbines is if the emission rates take into account the PM emissions associated with the add-on controls (i.e., SCR and oxidation catalysts). The PM emission rates estimated in PSE Fredonia Expansion Project include contributions from sulfur and ammonia reactions in the catalysts.

Table 8. BACT PM Permitted Limits for Simple Cycle Gas Turbine in Washington State			
Facility, Turbines, and Add-On Controls	**PM (lb/hr)**	**Size (MMBtu/hr)**	**PM (lb/MMBtu)**
PSE Fredonia (PSD-X82-09), Units 1 & 2, Simple Cycle, Westinghouse W501D, 104 MW each	104 combined	Gas: 1119 Distillate: 1120	Gas: 0.046 Distillate: 0.046
PSE Fredonia (PSD-01-04), Units 3 & 4, Simple Cycle, Pratt & Whitney FT-8 Twin Pac, 54 MW each, SCR & Oxidation Catalyst	31	Gas: 516 Distillate: 507	Gas: 0.060 Distillate: 0.061

From Tables 8 and 9, it is clear that the proposed PSE Fredonia Project will have lower PM limits (lb/MMBtu) comparing with current operating PM BACT limits issued within Washington state. Ecology found that when backup ULSD is used, the proposed PM BACT limits for any options also have lower PM limits (lb/MMBtu) compared with York Plant Holding's proposed PM BACT limit of 0.041 lb/MMBtu (calculated by dividing the mass limit of 15 lb/hr by the turbine heat input of 365 MMBtu/hr ULSD as the fuel) for a simple cycle turbine with the same add-on controls as PSE proposed. The Pennsylvania Department of Environmental Protection issued this draft permit in September 2011.

Ecology is aware that combined cycle facilities in Washington State are generally permitted with lower PM limits. However, Ecology believes that combined-cycle turbines permitted limits cannot be used to set up PM BACT limit for simple cycle turbines. The important difference is that simple cycle turbines have a higher exhaust temperature than combined-cycle turbines, which use a heat recovery boiler to recover some of the waste heat in the turbine exhaust in order to generate additional power. A higher exhaust temperature is likely to cause more PM to be formed in the oxidation catalyst and SCR system in simple cycle turbines compared with a lower exhaust temperature combined-cycle facility.

3.2.3. PM BACT Conclusion

Table 9. PM BACT Summary for the Combustion Turbines							
		Proposed BACT Limit					
		Natural Gas		**ULSD**			
PM	**BACT Control Technology**	**lb/hr**	**lb/MMBtu**	**lb/hr**	**lb/MMBtu**	**Averaging Time**	**Compliance Method**
GE 7FA.05	Good combustion practices, primary use of natural gas, and annual fuel use restrictions	47.7	0.027	38.5	0.027	Three 1-hr runs	Stack Test
GE 7FA.04		46.4	0.030	38.4	0.028		
Siemens 5000F4		40.0	0.020	34.6	0.025		
GE LMS100		17.8 (×2)	0.029	26.7 (×2)	0.040		

PSE Fredonia proposed the PM BACT limits based on mass emission rates (lb/hr). In addition to lb/hr mass emission limits, Ecology is also imposing PM BACT emissions limits on a heat input basis (lb/MMBtu). Ecology believes that a concentration-based BACT limit (i.e., ppm, lb/MMBtu) is necessary for determining compliance at the control technology's performance level, and for comparison between similar source types. This approach also conforms to EPA guidance stated in the draft NSR workshop manual (1990, pg. H.5): "In general, it is best to express the emission limits in two different ways, with one value serving as an emission cap (e.g., lbs/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." The PM emissions limits as shown in Table 9 are derived directly from the turbine vendors' (GE and Siemens) performance specifications, which were modeled to reflect site conditions, anticipated operating loads, fuel consumption, and fuel characteristics. As discussed above, even when using good combustion practices, PM emissions can still vary with turbine design and natural gas quality. Turbine design is not a consideration under PSD review, and natural gas quality is determined by the natural gas source used for supply. There are no alternate sources of natural gas available at this site. The natural gas received from Canada has a low sulfur content compared to other fuels. For fuel oil combustion, the cleanest available fuel choice is ULSD fuel, which has a maximum sulfur content of 0.0015% by weight. Annual ULSD firing is limited to a maximum fuel use listed in Table 4, depending on turbine options. Consequently, Ecology believes the proposed PM emission limit has been specified using the best information available, and BACT is good combustion practices, primary use of natural gas, and fuel use restrictions.

3.3. BACT for H_2SO_4 Mist from Turbines

The objective of this analysis was to determine BACT for H_2SO_4 emissions from any of the four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD. The total annual operation is based on the maximum amount of fuel use and types, which is summarized in Table 4.

H_2SO_4 emissions are the result of oxidation of fuel sulfur during combustion. SO_2 is the dominant sulfur oxide formed in gas turbines, while a smaller amount of sulfur is oxidized to sulfur trioxide (SO_3). Additional oxidation also occurs at the oxidation catalyst. SO_3 combines with water vapor in the exhaust and in ambient air to form H_2SO_4. Because H_2SO_4 also readily reacts with NH_3, SCR systems tend to help inhibit H_2SO_4 emissions. In the PSE Fredonia Project, the estimated total oxidation SO_2 to SO_3 conversion rates (by % volume) across the turbine, and oxidation and SCR catalysts are assumed to be 64% for the three GE options, and 67% for the Siemens option. The effect of the formation of ammonium sulfate and bisulfate to reduce direct H_2SO_4 emissions was not accounted for in this analysis.

3.3.1. Control Technology Review

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The primary fuel for this project is natural gas, which has a low sulfur content compared to other fuels. When the unit is firing fuel oil, the unit will fire ULSD fuel oil, which has a sulfur content of 0.0015% sulfur by weight. The selection of natural gas as the primary fuel and ULSD as the backup fuel provides inherently low SO_2 emissions, thus controlling the formation of H_2SO_4.

A search of the RBLC for simple cycle turbines permitted did not show any control technology for minimization of H_2SO_4 mist emission other than use of low sulfur content fuels.

Flue gas desulfurization (FGD) is an add-on control that removes sulfur from the combustion exhaust. FGD has not been found to be financially feasible for a natural gas fired turbine, and has not been used in practice. These types of control devices are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO_2 concentrations in flue gases from natural gas combustion are too low for the control technologies to work effectively, be technologically feasible, or cost-effective. As a result, Ecology is not proposing to require any add-on controls as BACT for this project.

3.3.2. Determination of Applicable H_2SO_4 BACT Emission Limitation

Very similar to PM, H_2SO_4 emissions can vary with turbine design, natural gas quality, and add-on controls. Turbine design is not a consideration under PSD review, and natural gas quality is determined by the natural gas source used for supply. There are no alternate sources of natural gas available at this site. Add-on controls, such as oxidation catalysts, can change the H_2SO_4 emission a great deal as discussed earlier. Ecology did not find any similar size simple cycle turbines used in Washington state to provide a meaningful comparison. The only simple cycle turbine project in Washington state having a H_2SO_4 BACT limit is PSE Fredonia Units 3 and 4 PSD permit (PSD-01-04), which includes two Pratt & Whitney FT-8 Twin Pac simple cycle turbines, 54 MW each. The permit limits H_2SO_4 emissions to 88 lb/day while firing either natural gas or distillate oil with sulfur content less than 0.01 percent. Taking the turbine size into consideration (516 MMBtu/hr), the H_2SO_4 emission rate is approximately 0.0072 lb/MMBtu. However, this emission was based on a 20% SO_2-SO_3 conversion across the oxidation catalyst instead of 60% assumed in this project. As mentioned in the PM BACT section, simple cycle turbines have a higher exhaust temperature, which is likely to cause much more SO_3 (and therefore H_2SO_4) to be formed in the oxidation catalyst because there is a nonlinear (exponential) relationship between exhaust temperature and SO_2 to SO_3 conversion. As a result, a SO_2 conversion assumption in the range of 60% is reasonable and consistent with literature.[5] In summary, it is not surprising that the proposed project will have higher H_2SO_4 emission rates due to the installation of the oxidation catalysts and the use of a high, more conservative SO_2 conversion assumption. Ecology believes that the proposed limits in Table 10 meet BACT requirements.

5

<http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/PM%20White%20Paper%20for%20BAAQMD%20020310.ashx>

3.3.3. H_2SO_4 BACT Conclusion

Table 10. H_2SO_4 Mist BACT Summary for the Combustion Turbines

H_2SO_4 Mist	BACT Control Technology	Fuel Type: Natural Gas lb/hr	Natural Gas lb/MMBtu	ULSD lb/hr	ULSD lb/MMBtu	Averaging Time	Compliance Method
GE 7FA.05	Good combustion practices, primary use of natural gas, and annual fuel use restrictions	22.0	0.0097	3.4	0.0015	24-hour	Stack Test
GE 7FA.04		18.7	0.0097	3.0	0.0015		
Siemens 5000F4		23.0	0.0103	3.4	0.0016		
GE LMS100		8.7 (x2)	0.0098	1.3 (x2)	0.0015		

PSE Fredonia proposed the H_2SO_4 BACT limits in terms of lb/hr. In addition to that, based on the same reason stated in the PM BACT section, Ecology also imposes H_2SO_4 BACT emissions limits on a heat input basis (lb/MMBtu) as shown in Table 10. These emission rates are based on turbine vendors' performance specifications considering both the site-specific natural gas information relating to the total sulfur content, and installation of the SCR and oxidation catalyst controls. Ecology believes the proposed H_2SO_4 emission limit has been developed using the best information available. BACT is the use of good combustion practices, primary use of natural gas, and annual fuel use restrictions. The maximum sulfur content of the natural gas is estimated to be 3.48 grains (gr) total sulfur per 100 standard cubic feet (scf) on an hourly basis, and to be 2.25 gr total sulfur per 100 scf on an annual average.

3.4. BACT for CO from the Siemens Turbine Only

The objective of this analysis was to determine BACT for CO emissions from the Siemens SGT6-5000F4 frame turbine option. A BACT analysis was not required for CO emissions from the other three turbine options since annual emissions will be below the PSD thresholds. The Siemens SGT6-5000F4 will be dual fueled by natural gas and ULSD. The total annual operation is based on 4,959,209 MMBtu/yr, in which the ULSD is expected to be utilized up to 663,277 MMBtu/yr.

CO is a colorless gas that is a product of incomplete combustion. Ecology began its BACT analysis by evaluating the most effective control device and/or technique that has been achieved in practice at similar facilities. Ecology's BACT determination is explained below.

3.4.1. Control Technology Review

A search of the RBLC and other sources mentioned early in this section found that CO BACT technology for a simple cycle gas turbine is good combustion control, and in some cases an oxidation catalyst is used.

Good combustion controls

CO emissions are formed in combustion turbines as a result of incomplete combustion. Similar to generation of NO_X emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally, the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_X emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_X emissions. Therefore, the key to the best design lies in the ability to use all the oxygen available with input air for combustion, while controlling the temperature such that NO_X formation can be minimized. Good combustion practices utilize "lean combustion." Lean combustion uses a large amount of excess air to produce a cooler flame temperature to minimize NO_X formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion and minimize CO emissions.

Ecology has identified good combustion practices as an available combustion control technology for minimizing CO formation during combustion. Gas turbine combustion technology has significantly improved over recent years with respect to lowering CO emissions. In some of the recent permits (Table 11), CO emissions can even reach 4 ppm @ 15% O_2 without post-combustion control when firing natural gas.

Oxidation catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst at elevated temperatures within the exhaust stream, CO will react with oxygen, converting it to carbon dioxide (CO_2). No supplementary reactant is used in conjunction with an oxidation catalyst.

For two decades, oxidation catalysts have been employed successfully for both natural gas and oil-fired combustion turbines. Similar to SCR systems, for oxidation catalysts to be successful in oil-fired combustion turbine applications, it is generally best when both the amount and the sulfur content of the oil fired is low to minimize the contamination of the catalyst with sulfur compounds.

CO oxidation catalysts can be considered technically feasible for use in simple cycle peaking applications. Therefore, installation of a CO oxidizing catalyst on the turbines is considered available BACT for this project.

Based on the above analysis, Ecology has determined that the combination of good combustion practices to reduce the formation of CO during combustion, and an oxidation catalyst to remove CO from the gas turbines exhaust is BACT.

3.4.2. Determination of Applicable CO BACT Emission Limitation

To establish what level of BACT emissions limits for CO has been permitted and achieved in practice for this type of facility, Ecology reviewed the CO emissions limits of other large simple cycle power plants at the EPA RBLC, CARB BACT clearinghouse, recent projects undergoing CEC licensing, and BACT guidance documents from other regional and local agencies.

CARB's BACT[6] guidance document for electric generating units rated at greater than 50 MW indicates that BACT for the control of CO emissions from a simple cycle gas turbine is 6 ppmvd @ 15% O_2.[7] The *Bay Area Air Quality Management District* (BAAQMD)'s BACT guidelines specify that, for natural gas-fired, simple cycle gas turbines larger than 40 MW, a CO limit of 6 ppmv @ 15% O_2 has been "achieved in practice."[8] The San Joaquin Valley Air Pollution Control District's (SJVAPCD) BACT guidelines contained determinations for gas turbines larger than 50 MW with uniform load and without heat recovery to be 6 ppmv @ 15% O_2 achieved in practice.[9] A July 2011 BACT guideline from Massachusetts Department of Environmental Protection (MassDEP)[10] specified that a CO limit of 5 ppmv @ 15% O_2 is considered the top case for a simple cycle turbine >10MW/hr firing with natural gas or ULSD.

The proposed BACT emission by the applicant for Siemens SGT6-5000F4 are 4.0 ppmvd and 12.0 ppmvd, corrected to 15% O_2 when burning with natural gas and ULSD, respectively, both on a 3-hour average. These levels are within the lower range of recent BACT determinations from the database searched, and the guidance documents Ecology reviewed. However, they are not the most stringent levels being permitted.

A summary of recent CO BACT determination for the similar size simple cycle turbine is shown in Table 11. These limits are all lower than PSE's proposed limits. As listed in this table, the lowest CO BACT limits are 2 ppmvd @ 15% O_2 firing natural gas in two permits. However, for these two turbines, one permit was recently issued and the other permit is still under review. At the time of drafting this TSD, neither of them has been yet been constructed, so no performance data are available. This 2 ppm permit limit therefore is not considered achieved in practice. Ecology is not aware of data that shows compliance with the 2.0 ppm limits has been demonstrated in practice for a similar size simple cycle gas turbine. For fuel oil firing, the lowest CO BACT limits are 8 ppmvd @ 15% with good combustion practices.

As a result, Ecology requested PSE Fredonia to investigate if they can meet the 8 ppm CO limit when firing ULSD. PSE found that an 8 ppm limit is achievable with a larger oxidation catalyst

[6] Note to reader: California's BACT process is more like what other states are required to do for nonattainment NSR than PSD permitting. However, once a control level and technology are utilized in California, the technology and the emission limitation become achievable (demonstrated in practice or existing in other agency permits) for purposes of a BACT analysis in Washington state.
[7] http://www.arb.ca.gov/energy/powerpl/guidocfi.pdf
[8] http://hank.baaqmd.gov/pmt/bactworkbook/
[9] http://www.valleyair.org/busind/pto/bact/chapter3.pdf
[10] http://www.mass.gov/dep/air/approvals/bactcmb.pdf

bed, and accepted Ecology's suggestion to limit CO to 8 ppm rather than 12 ppm while burning distillate fuel in the Siemens SGT6-5000F4 combustion turbine.

Ecology has concluded that the proposed limits meet BACT requirements.

Table 11. Selected CO BACT for the Similar Size Simple Cycle Turbine

Facility	Permit Approved Date	Model Type	CO Emissions	Fuel	Control
Mountain Creek Steam Electric Station	1/12/2011	(2) 198 MW SGT 5000 F Simple Cycle	2 ppmvd @ 15% O_2 (60-100% loads) 3-hr average	Natural Gas	Oxidation catalyst
Marsh Landing Generating Station	CEC review in progress	(4) 190MW SGT6-5000F Simple Cycle	2 ppmvd @15% O_2 3-hr average	Natural Gas	Oxidation catalyst
Progress Bartow Power Plant	6/12/2008	(1) 195 MW SGT6-5000F Simple Cycle	4.1 ppmvd @ 15% O_2	Natural Gas	Good combustion
			8 ppmvd @ 15% O_2	Fuel Oil	
Great River Energy-Elk River	7/1/2008	(1) 2169 MMBTU/hr GE 207FA Simple Cycle	4 ppmvd @ 15% O_2 >=70% load; 4-hr rolling average	Natural gas	Good combustion
			10 ppmd @ 15% O_2 >=70% load; 4-hr rolling average	Fuel Oil	

3.4.3. CO BACT Conclusion

Ecology has determined that the use of a CO catalyst and good combustion practices together with a limited fuel use meet BACT for minimizing CO for the Siemens SGT6-5000F4 turbine option. With these emission controls, Ecology is proposing setting the CO BACT emission limits as shown in Table 12.

In addition, the CO CEMS accuracy is about 0.5 ppm in a low operational range in general and CO emissions from the proposed turbine are within 4 ppm during normal operations firing with natural gas. The achievable relative accuracy is about 12.5 percent. As a result, Ecology allows the relative accuracy of the CO CEMS to go up to 15% instead of 5% listed in Section 13.2 of 40 CFR part 60 Appendix B, Performance Specification 4a.

Table 12. CO BACT Summary for the Combustion Turbine							
		Fuel Type					
		Natural Gas		ULSD			
CO	BACT Control Technology	ppm @ 15% O_2	lb/hr	ppm @ 15% O_2	lb/hr	Averaging Time	Compliance Method
Siemens SGT6-5000F4	Good combustion practices, an oxidation catalyst, and annual fuel use restrictions	4	14.4	8	33.1[a]	1-hr	CEMS

[a] Prorated value based on the 8 ppm BACT limit: 49.6 lb/hr x 8 ppm/12 ppm = 33.1 lb/hr

Since the CO BACT limit on distillate drops from 12 ppm to 8 ppm, the corresponding mass rate (lb/hr) will drop too. Instead of requesting vendor specifications, PSE accepted Ecology's prorated mass rate of 33.1 lb/hr instead of 49.6 lb/hr (corresponding to 12 ppm at worst-case operating scenario (75% load, ambient temperature of 7ºF, and relative humidity of 40%) when firing with ULSD. Because of a low CO BACT limit on distillate, the annual CO emissions will change as well. Ecology estimated that new annual CO emissions will be 157.4 tpy (compared to 159.9 tpy) assuming no emission changes during SUSD on distillate due to the new CO BACT limit on distillate. The total CO emissions from SUSD on distillate are 15.2 tpy (5 tpy emission are from shutdown only). This is a small fraction of annual CO emissions. Therefore, Ecology considers it is safe not to include the potential emission reduction from SUSD on distillate in the annual limits.

3.5. BACT for GHG from Turbines

The objective of this analysis was to determine BACT for GHG emissions from any of the four combustion turbine options. The simple cycle turbines will be dual fueled by natural gas and ULSD with total annual operation based on the maximum amount of fuel uses and types. This information is summarized in Table 4.

As discussed in Section 2, CO_2 is by far the dominant GHG pollutant for the project. Even with GWPs of 21 for CH_4 and 310 for N_2O (the GWP of CO_2 is 1), these two pollutants will contribute less than 3% to the project's total CO_2e emissions. For these reasons, this BACT analysis focuses primarily on the CO_2 emissions from the gas turbine stack(s). However, GHG emissions from N_2O and CH_4 are also included in the final GHG BACT emission limits. In developing the GHG BACT limits, Ecology has chosen to use the factors derived from the source testing performed at PSE's Sumas and Mint Farm Generating Stations in 2009.

A 5-step, top-down GHG BACT analysis for the simple cycle combustion turbine options was provided by PSE per Ecology's request, and evaluated by Ecology.

3.5.1. Control Technology Review

According to EPA's recent guidance,[11] available control technologies should include lower emitting processes, practices and designs, the use of add-on controls, and combinations thereof. Potentially available BACT technologies for this project are summarized below.

Fuel selection

The type of fuel burned determines the amount of GHG pollutants emitted. Viable existing local fuel options for the proposed project include natural gas and fuel oil. Burning natural gas produces less CO_2 than burning fuel oil due to the lower carbon/hydrogen count in methane. According to EPA AP-42 emission factors, burning distillate fuel oil produces less CH_4 and N_2O emissions than burning natural gas. These lower CO_4 and N_2O emissions are offset by the higher CO_2 emissions from burning distillate oil resulting in an overall higher CO_2e emission rate for distillate oil compared to natural gas.

As discussed above in BACT sections, exclusive use of natural gas as fuel is not feasible. As a result, this project will be fueled primarily by natural gas with limited firing with ULSD.

Carbon capture and sequestration (CCS)

CCS is a technology that involves capture and storage of CO_2 emissions to prevent their release to the atmosphere. For a gas turbine, this includes removal of CO_2 emissions from the exhaust stream, transportation of the CO_2 to an injection site, and injection of the CO_2 into available sequestration sites. Potential CO_2 sequestration sites include geological formations (including oil and gas fields for enhanced recovery), and ocean storage.

Voluntary BACT analyses of CCS have been performed for two projects permitted in late 2010. The two projects are the Calpine Russell City Energy Center Project (which includes a combined cycle combustion turbine project), and the Portland General Electric's Port Westward II Project (which includes a simple cycle GE LMS100 gas turbine). In both BACT analyses, CCS was found to be unavailable or infeasible in practice.

PSE also identified a PSD Permit (SE-09-01) issued to Palmdale Hybrid Power Project (PHPP) in southern California by EPA Region 9 on October 18, 2011, that includes a GHG BACT analysis. This proposed project includes solar technology and two combined cycle GE Frame 7FA CCCTs to generate electrical power. EPA Region 9's BACT analysis for GHG emissions from the CCCTs considered two control technologies: (1) the use of new thermally efficient CCCTs and (2) the use of CCS. CCS was eliminated as technically infeasible for the PHPP and was not considered beyond BACT step 2.

[11] *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011.

In Ecology's independent BACT review, three additional combine cycle generating facilities were identified and evaluated. These facilities are the Pacificorp Lake Side Power Plant (PLSPP), UT (DAQE-AN0130310010-11); the Lower Colorado River Authority (LCRA)-Thomas C Ferguson plant (PSD-TX-1244-GHG); and the Pioneer Valley Energy Center (PVEC)-Westfield, MA (EPA draft PSD 052-042-MA15). The PLSPP permit was issued by Utah Department of Environmental Quality (DEQ) on May 4, 2011. The Utah DEQ concluded that high efficiency combustion turbine and HRSG design are the BACT for GHG. The LCRA permit was issued by EPA Region 6 on November 10, 2011. EPA Region 6 concluded that there is no commercially available CCS system to LCRA in the near term. In addition, even if technically feasible, the option was eliminated based on its cost-effectiveness. The PVEC draft permit prepared by EPA Region 1 was available for public comment from December 5, 2011to January 24, 2012. EPA Region 1 eliminated CCS technology for PVEC's proposed project as GHG BACT due to the energy, environmental, and economic impacts.

Ecology also identified four other combustion turbine permits involving GHG emissions, which are under review by state and local permitting authorities at the time of preparing this document. These projects are the Effingham County Power Project (GA, DNR), Cricket Valley Energy Project (NY, DEC), York Plant Holding Project (PA, DEP), and Wolverine Power-Sumpter Project (MI, DEQ). The use of CCS has been eliminated in these draft permits as BACT for GHG.

Within PSE's permit application BACT analysis, the applicant proposed to eliminate CCS because CO_2 capture is not technically feasible for a combustion turbine. PSE examined a list of 14 active and potential CCS projects published by the Global CCS Institute to search for similar projects to PSE's proposed turbine options. Of these 14 projects, 13 projects were pre-combustion capture technology, and only one project was post-combustion technology. In addition, PSE reviewed seven other post-combustion CO_2 capture and storage demonstration projects that were built and operated over the years, but are no longer in operation or on hold due to economic reasons,(including a demonstration scale capture technology at a Florida Power and Light (FP&L) natural gas combine cycle turbine power plant in Bellingham, Massachusetts). The increase in natural gas prices in 2004 to 2005 forced the FP&L power plant to operate in a peak load shaving mode, which rendered the CO_2 capture plant uneconomical after 14 years of operation (1991–2005). During this time, only a fraction of CO_2 from gas-turbine exhaust was captured, and provided for off-site sale. Sequestration was not attempted at the FP&L Bellingham plant.

PSE believes that carbon capture technologies are still demonstration projects for combined cycle facilities, and remains undemonstrated for simple cycle peaking application to date. However, this CO_2 capture technology consideration appears to be more of a cost issue instead of a technical feasibility issue. Based on available information, Ecology considers carbon capture from gas turbines to be technically feasible for the project.

The applicant also identified four potential sequestration options: enhanced oil recovery (EOR), geologic sequestration, silicate mineral reactions, and industrial reuse. In the Pacific Northwest, EOR opportunities do not exist due to the lack of oil and gas production areas. Pipelines do not exist for the transportation of CO_2 to distant oil and gas production areas to provide for EOR. Geologic sequestration, including deep saline formation, deep basalt formations, and the tectonic subduction zone, was also explored for this project. Geologic sequestration was found not to be a viable option, or within a reasonable distance of the project site (200 miles or more). In addition, two of the three approaches (deep basalt formations and injection in tectonic subduction zones) have not been demonstrated in practice. Silicate mineral reactions are also infeasible because the mineral deposit is undeveloped, there is no existing rail transport infrastructure to transport the minerals to and from the power plant site, and there is not a developed disposal sites to receive the reacted minerals. The costs to rectify these issues would become costs to be added to the economic analysis of CCS for this project.

Typical industrial uses of CO_2 such as welding operations, beverage carbonation, or use as a supercritical solvent do not qualify as permanent sequestration, and would not reduce CO_2 emissions. No established, large-volume, consumptive CO_2 industry is known to exist near the project site. In addition, a pipeline system to transport the CO_2 to such a user does not exist, and the cost to develop a pipeline would have to be borne by this project. As a result, PSE does not consider the carbon sequestration option to be technically feasible.

In spite of the technical infeasibility, PSE qualitatively performed a cost analysis for carbon capture and sequestration. Instead of a project/site specific cost estimate for implementing one of the CCS options discussed above, PSE considered the cost per ton of CO_2 avoided that others had developed. PSE then compared those projects' specifications with the proposed PSE Fredonia Project's specifications. PSE concluded that the fewer operating hours, additional steam requirement for the CO_2 capture system, heat rejection system with a bigger cooling duty, no available saline formation within a 50 mile radius of the facility, and a smaller size of a CCS system required for the PSE Fredonia Project will cause the cost per ton of CO_2 avoided to be much higher than currently acceptable economic thresholds. Given that carbon capture alone is demonstrated not to be economically viable for the PSE Fredonia Project, any of the sequestration options would add significantly to the project's cost. Therefore, CCS systems were determined to not be cost-effective, and were removed from further consideration in the BACT analysis for GHG. Ecology reviewed PSE's CCS technical and cost analysis, and concurs with the assessment.

Fuel efficient engine technology

CO_2e emissions are the direct result of the amount and type of fuel burned. Engines that are more efficient emit less CO_2e relative to the amount of electricity produced. Both Ecology and the applicant are aware that a combined cycle combustion turbine (CCCT) produces less GHG emissions per MW-hr of electricity generated due to the higher efficiency of the technology. However, a combined cycle generation facility is a different type of generation project that would not meet the PSE Fredonia Project requirements to respond to rapidly changing, and often short-term peak power demand on PSE's system. Simple cycle combustion turbines are best suited, and are more cost-effective for peaking applications. The applicant also investigated fast start versions of CCCT units, which have been recently announced by both Siemens and GE. PSE concluded that fast start CCCT are unproven technology and to their knowledge, neither company has commercially constructed and operated a fast start CCCT. In addition, the minimum size of vendors' currently proposed new fast start combined cycle units is 270 MW, which is above the capacity that PSE is seeking to meet projected needs. This technology also currently offers continuous emission guarantees only at approximately 50% load or 135 MW. Using combined cycle technology would require the project to be fundamentally redefined. Therefore, CCCT is not an available technology option for consideration in this BACT evaluation. After elimination of CCCT as a potential alternative, the use of a modern and efficient simple cycle gas turbine is the remaining control method.

Ecology requested that the BACT analysis include an efficiency evaluation of the different turbine options. Energy efficiency is a component of BACT that focuses on reduction of emissions through changes to the underlying process rather than using add-on control technology. GHG emissions are directly related to minimizing the quantity of fuel required to make electricity. This concept is reflected in the turbine's thermal efficiency so that a more efficient engine will reduce the GHG emissions operating under the same conditions.

PSE Fredonia has requested the ability to select one of four specified combustion turbine options after the permit is issued to allow the company to choose the best engine of the four options at the time they start construction. Ecology does not intend to require a single make or model through the BACT decision. Ecology understands that a high efficient engine does not necessary transfer directly to low GHG emissions because some operating parameters, (such as fuel type, operating loads, and operating hours), will affect the total GHG emissions from the project. The applicant's ultimate decision about which turbine engines to install will depend upon a variety other considerations, including but not limited to equipment availability, cost, start-up time, operational performance, reliability, and maintenance issues. Ecology is willing to give the flexibility to the applicant, but in the meantime, through this analysis, make sure these four options proposed are all efficient engines suitable for the project.

Overall, besides the proposed four modern and efficient simple cycle turbine engine generators, the applicant also identified three other options (58 MW Pratt and Whitney FT8, 41 MW GE LM6000 simple cycle turbine engine generators, and 17 MW Wartsila model 18V50DF reciprocating engines) that could be used to satisfy the project's rapid-start peaking electricity generation. Of the available engine technologies, the Wartsila 18V50DF is not technically feasible because it could not satisfy other air permitting requirements. Ambient air quality modeling demonstrated that off-site impacts from the Wartsila 18V50DF engine emissions would significantly exceed the new federal 1-hour NO_X NAAQS at locations near the FGS.

The remaining six feasible turbine options' estimated CO_2 and CO_2e emission rates in lb/MW-hr of electricity generated are listed in Table 13. Table 13 also includes emission rates Ecology identified through other PSD permits.

Ecology found that a draft PSD permit issued in September 2011by the Pennsylvania (PA) Department of Environmental Protection (DEP) approved the installation of any two simple cycle turbines among three turbine options (Rolls Royce Trent 60, 61.5MW each; Pratt & Whitney FT8, 49MW each; and GE LM-6000, 47MW each). All of these turbine options are proposed to have SCR and oxidation catalyst to control emissions. PA DEP concluded that the GE LM-6000 option is the most efficient turbine option. The BACT limits are set as 1,330 lb CO_2e/MW-hr when firing with natural gas and 1,890 lb CO_2e/MW-hr when firing with ULSD. In addition, Ecology found in the Appendix D of the Port Westward II Project Voluntary GHG BACT analysis, the applicant estimated CO_2 emission rates from the proposed LMS100 simple cycle turbine to be 1,047 lb/MW-hr. However, this limit is not set as a BACT limit. Ecology also found that in Palmdale Hybrid Power Project (PSD SE 09-01) fact sheet, the permitting agency (EPA Region 9) estimated CO_2 emission rates from the proposed 7FA CT operating in simple cycle mode with a gross output of 154 MW each to be 1,319 lb/MW-hr.

Table 13. GHGs BACT Summary for the Combustion Turbines[1]

Turbine Options Without CCS	Emission Rate (lb CO_2/MW-hr)	Emission Rate (lb CO_2e/MW-hr)
LMS-100	1,044	1,052
LM-6000	1,145	1,153
7FA.05	1,176	1,185
5000F4	1,177	1,186
7FA.04	1,182	1,191
FT8-3	1,226	1,235
7FA turbine operating in simple cycle mode[2]	1,319	
GE LMS-100 simple cycle turbine[3]	1,047	
GE LM-6000 simple cycle turbine[4]		1,330 (gas) 1,890 (ULSD)

[1] Assumption except for the York Plant Holding Project:
a) Natural gas is the only fuel.
b) Turbines are operated under full load conditions.
c) Annual hours of operation are 8,760 hr.

[2] Palmdale Hybrid Power Project: “Fact sheet and ambient air quality impact report” Table 7-10, p. 30.

[3] Portland General Electric’s Port Westward II Project, Appendix D, Table 4-1, p. 7.

[4] York Plant Holding, Inc. Project, p. 13. The emission rate is based on the proposed operating condition. Other two approved simple cycle turbines (Rolls Royce Trent 60 & Pratt & Whitney FT8) will have higher emission rates, but the permit and TSD do not include these limits.

The least efficient and highest emitting option proposed by PSE is the Pratt & Whitney FT8-3. Because this turbine option is also one of the most expensive to purchase and offered no significant advantages, the applicant dropped it from further consideration. The remaining five turbine options emit less CO_2e per MW-hr and are, therefore, considered to be feasible and the most effective controls for further evaluation relative to their emission performance and cost-effectiveness.

Table 14 summarizes the incremental cost analysis for CO_2 reduction via changes in unit thermal efficiency. For purposes of calculating the cost of incremental CO_2e reduction, the analysis treats the fifth-ranked option, 7FA.04, as the base case, and calculates the additional cost per ton of using the other turbine models to further reduce CO_2e emissions. The analysis shows that further CO_2e reductions would cost between $710 and $4,660 per ton of CO_2e removed. This incremental cost range appears to be in excess of costs that have been considered "achievable" in other GHG BACT analyses, or in EPA's initial guidance on what might constitute BACT for GHGs. The calculated incremental costs are at least 10 times higher than the current market price of CO_2 offsets and credits (currently about $9.07 per ton) and greatly exceed the $20 per ton CO_2e approximate social cost of carbon recently cited by EPA.[12]

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options

	LMS100	LM-6000	7FA.05	5000F4	7FA.04
Emissions Calculations					
Plant Capacity, net (MW)	199.7	165.1	209.4	207.1	182.3
Generation (MW-hr), 200MW@7.5%CF[1]	131,400	131,400	131,400	131,400	131,400
Heat rate @ full load (Btu/kWh, HHV)	9,007	9,871	10,145	10,152	10,193
Fuel CO_2 Rate (lb/MMBtu, HHV)[2]	115.9	115.9	115.9	115.9	115.9
Fuel CO_2e Rate (lb/MMBtu, HHV)[3]	116.8	116.8	116.8	116.8	116.8
Plant CO_2e Emissions Rate (lb/MW-hr)	1,052	1,153	1,185	1,186	1,191
Annual CO_2e Emissions (tpy)	69,118	75,748	77,850	77,904	78,219
Emissions Rank (1 = lowest emitting)	1	2	3	4	5
CO_2e Reduction from Base Unit (tpy)	9,101	2,471	368	315	0
Cost Calculations					
Plant Book Life (yrs)	35	35	35	35	35
PSE Discount Rate	8.10%	8.10%	8.10%	8.10%	8.10%
Annual O&M					
Fixed O&M (FOM) ($/kW-yr)	15.71	19.06	11.48	11.76	12.32
First-Year FOM ($/yr)	3,136,522	3,146,952	2,403,015	2,436,339	2,246,140
FOM Escalation Rate(1)(%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
FOM Levelized Cost ($/yr)	4,063,695	4,998,100	3,113,360	3,156,534	2,910,111
Variable O&M (VOM) ($/MW-hr)	3.58	4.34	11.88	10.28	10.68
First Year VOM ($/yr)	470,713	570,584	1,560,650	1,350,846	1,402,785
VOM Escalation Rate(1)(%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
VOM Levelized Cost ($/yr)	609,858	906,221	2,021,987	1,750,164	1,817,457
Fuel ($/MMBtu, HHV)	8.08	8.08	8.08	8.08	8.08
First Year Fuel ($/yr)	9,562,840	10,480,159	10,771,068	10,778,500	10,822,030

[12] EPA Office of Air Quality Planning and Standards (OAQPS), June 17, 2011: Panel Outreach Meeting with SERs: *Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units*, p. 62.

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options					
	LMS100	**LM-6000**	**7FA.05**	**5000F4**	**7FA.04**
Fuel Escalation Rate(%/yr)[4]	3.00%	3.00%	3.00%	3.00%	3.00%
Fuel Levelized Cost ($/yr)	12,389,669	16,644,959	13,955,056	13,964,685	14,021,083
All-In CapEx ($)	279,000,000	274,000,000	198,000,000	191,000,000	185,000,000
Capital Recover Factor	8.67%	8.67%	8.67%	8.67%	8.67%
Annual CapEx ($/yr)	24,182,437	23,749,060	17,161,729	16,555,002	16,034,949
Total Levelized Annual Cost ($/yr)	41,245,660	46,298,340	36,252,133	35,426,384	34,783,600
Levelized Cost (Savings) Over Base ($/yr)	6,462,059	11,514,739	1,468,532	642,784	$0
Incremental Cost-Effectiveness ($/ton CO_2e)	$710	$4,660	$3,987	$2,043	$0

[1] Assuming the project would generate 131,400 MW-hrs of electricity per year for all options.
[2] Assuming natural gas would be used as the fuel.
[3] Based on source testing at PSE's Sumas and Mint Farm Generating Stations in 2009, CO_2 emissions account for approximately 99.27% of total CO_2e emissions.
[4] Assuming an escalation rate of 3% as an average inflationary number. This number falls within the range of historical inflation.

The applicant decided that the most expensive option, the LM6000, would not be pursued for the project because it does not offer any significant advantages. The applicant requested Ecology to recognize that the installation and operation of any one of four turbine options (F7A.04, GE F7A.05, Siemens SGT6-5000F4, and GE LMS100) satisfies the BACT requirements for GHGs.

Considering the fact that the proposed annual operating scenarios and operating hours are different depending on the turbine option, the least efficient make or model is not necessarily the highest annual emitting option. For example, for a peaking facility in which a turbine does not operate all the time, a more efficient make or model would still have higher annual GHG emissions if more operating hours were proposed (i.e., use more fuel), compared with a less efficient make or model with fewer operating hours (i.e., use less fuel). As a result, Ecology considered engine efficiency together with proposed operating hours associated with all four turbine options during the BACT analysis. In this project, the least efficient engine (7FA.04) generates the least annual GHG emissions while the most efficient engine (GE LMS100) generates the highest annual GHG emissions because of more operation hours (i.e., more fuel use). As a result, Ecology agrees with the applicant that any of the four turbine options satisfies BACT requirements for GHG.

3.5.2. Determination of Applicable GHG BACT Emission Limitation

The numbers presented in Tables 13 and 14 are used to compare the efficiency among turbine models, and do not translate directly into permit limitations. Permit limitations include the effects of other operational parameters and considerations, such as fuel types, operating hours, loads, and the numbers and durations of start-ups and shutdowns.

Ecology used performance data from the turbine vendors and the operational scenarios, (including SUSD), to estimate CO_2 emissions. Emissions for both CH_4 and N_2O utilized the results of source testing at PSE's Sumas and Mint Farm Generating Stations in 2009 to estimate the GHG emissions. This information is provided in Tables 15 below. All proposed BACT limits for this project are lower than the York Plant Holding Project proposed BACT limits as listed in Table 13. The proposed BACT limit for the York Plant Holding Project is the only available GHG BACT limit for a simple cycle turbine. In addition, New York[13] has proposed to restrict a simple cycle combustion turbine (>25MW) to emit less than 1,450 lb CO_2 per MW-hr. All proposed BACT limits for this project are lower than this number as well. Therefore, Ecology believes these numbers meet the BACT requirement.

3.5.3. GHG BACT Conclusion

Ecology has determined the installation and operation of any of PSE's proposed simple cycle turbines as meeting BACT for GHG. With this BACT determination, permit conditions must be developed to ensure PSE installs the proposed energy efficient turbine(s), and will continue to operate the turbine(s) in an energy efficient manner. To ensure these two goals are met, Ecology is proposing in the permit two emission limits for GHGs as listed in Table 15. In addition, Ecology is requiring appropriate monitoring recordkeeping and reporting. These emission limits are based on a review of emissions data from manufacturer guarantees that include factors such as partial load, start-ups, and shutdowns. These factors affect the turbine's efficiency. In addition, these emission limits also incorporate emissions from CH_4 and N_2O using the emission factors from previous source testing conducted at PSE's Sumas and Mint Farm Generating Stations in 2009.

Table 15. GHG BACT Summary for the Combustion Turbines

GHGs	BACT Control Technology	BACT Limits		Compliance Method
GE 7FA.05	High-efficiency simple cycle gas turbine technology, Primary Use of Natural Gas and annual fuel use restrictions	1,299	lb CO_2e/MW-hr net output, 365-day rolling average	Initial stack test for CO_2; CO_2 CEMS (only if elected) and recordkeeping
		311,382	tpy as CO_2e, 12-month rolling total	
GE 7FA.04		1,310	lb CO_2e/MW-hr net output, 365-day rolling average	
		274,496	tpy as CO_2e, 12-month rolling total	
SGT6-5000F4		1,278	lb CO_2e/MW-hr net output, 365-day rolling average	
		301,819	tpy as CO_2e, 12-month rolling total	
GE LMS100		1,138	lb CO_2e/MW-hr net output per unit, 365-day rolling average	
		327,577	tpy as CO_2e, 12-month rolling total	

[13] http://www.dec.ny.gov/regulations/79556.html

In order to accurately measure efficiency, Ecology is requiring PSE Fredonia to measure the actual heat input in MMBtu/hr and the pounds of CO_2 on an hourly basis with a CO_2 emission monitor. This analysis can be completed according to 40 CFR Part 75, Appendices F and G. As an alternative, PSE Fredonia may install, calibrate, and operate a CO_2 CEM, a volumetric stack gas flow monitoring system, and an automated data management system to measure and record CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.

To demonstrate compliance with the GHG BACT limit of lb CO_2e per MW-hr (net), the measured hourly CO_2e emissions are divided by the net hourly energy output, and averaged on a daily basis. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling average.

An initial stack test is required to establish the actual quantities of CO_2 emissions from the turbine. An initial stack test is not required for CH_4 and N_2O because GHG emissions from N_2O and CH_4 are less than 3% of the total CO_2e emissions from any proposed turbine options, and are considered at a de minimis level in comparison to the CO_2 emissions.

3.6. BACT for GHG from Switchyard Breakers

The circuit breakers are subject to BACT for GHG emissions. The only GHG emitted from circuit breakers is sulfur hexafluoride (SF_6). SF_6 is a potent GHG with a global warming potential of 23,900. With the proposed control technologies, CO_2e emissions are estimated at 120.1 tpy.

The inherently lower-emitting control options for GHG emissions include:

- Use of oil-filled circuit breakers—these types of circuit breakers do not contain any GHG pollutant.
- Totally enclosed SF_6 circuit breakers—these types of circuit breakers have a maximum leak rate of 0.5% per year by weight.

Although oil-filled breakers contain/emit no GHG, oil presents other environmental and safety risks. An oil release and/or fire could result in the event of overheating and rupture of the breaker. The advantages of the use of SF_6 in circuit breakers include low operating energy requirements, no fire risk, no toxic hazards, corrosion protection, limited space requirements, extremely low failure rate, low maintenance costs, and long service life.

The applicant reviewed a recent combined cycle turbine project (PHPP PSD SE 09-01) issued by EPA Region 9, and found the enclosed-pressure SF_6 circuit breakers with 0.5% annual leakage rate and leak detection systems was selected as BACT. Ecology's independent search found the same BACT determination has been made for circuit breakers in other five projects: the Calpine Russell City Energy Center permit, California (a combine cycle turbine project and a voluntary BACT), the Abengoa Bioenergy Biomass of Kansas draft permit, Kansas (a biomass to ethanol and biomass-to-energy production project), the Crawford Renewable Energy permit, Pennsylvania (a waste tires-to-energy project), the Pioneer Valley Energy Center application supplement, Massachusetts (a combined cycle turbine project), and the Thomas C. Ferguson Power Plant permit, Texas (a combined cycle turbine project).

As a result, the applicant proposed that SF_6 filled breakers are selected as BACT. Ecology agrees that the non-air quality impacts of oil-filled breakers are significant enough to select SF_6 filled circuit breakers as BACT.

Additionally, Ecology is requiring the SF_6 filled breakers be equipped with a leak detection system to identify SF_6 leaks immediately so that corrective actions can be taken in time to limit releases.

3.7. BACT for Emergency Generators

A diesel-fired compression ignition (CI) engine generator is proposed as the only technically feasible option to supply the new units' critical electrical loads in the event power could not be back-fed from either the site's 230 kilovolt (kV) or 115 kV transmission systems. A natural gas-fired generator is not a reasonable option because there is a risk for significant damage to the gas turbine(s) and other power plant system if both a power grid outage and a natural gas outage were to occur at the same time. This occurrence could happen in the event of a strong earthquake or a natural gas pipeline explosion.

BACT determinations on emergency generators are uncommon. Current BACT guidelines and determination published in the RBLC and by the following three California Districts were reviewed for BACT for the PSE's proposed emergency generator:

- BAAQMD BACT Guideline for emergency CI internal combustion (IC) engines >50 hp (http://hank.baaqmd.gov/pmt/bactworkbook/default.htm)
- SJVAQMD BACT Guideline 3.1.1 for emergency diesel IC engines (www.valleyair.org/busind/pto/bact/chapter3.pdf)
- SCAQMD LAER/BACT Determinations for emergency CI engines (http://aqmd.gov/bact/aqmdbactdeterminations.htm)

Current BAAQMD, SCAQMD, and SJVAQMD BACT guidelines require new stationary emergency CI engines to meet applicable EPA NSPS or CARB tier standards for NO_X, CO, PM_{10}, and VOC. These same guidelines require the use of ULSD to control SO_2 emissions.

Federal Tier 2 standards for nonroad CI engines currently apply to new stationary emergency standby engines greater than 761 break-horsepower (bhp), or 560 brake-kilowatt (bkw) (40 CFR Part 60, Subpart IIII). Emergency engines are exempt from the more stringent Tier 4 requirements in the NSPS. CARB is in the process of adopting rule revisions to retain a 0.15g/bhp-hr limit for PM, and align the other pollutant emission standards with federal NSPS requirements for emergency standby CI engines. This change reflects CARB's recent finding that add-on controls (i.e., SCR and diesel particulate filter technology) are not justified for emergency engines due to significant economic and operational constraints.[14] This CARB finding is consistent with EPA's rationale for exempting emergency CI engines from Tier 4 requirements.

PSE proposes the purchase and install one 600 kW diesel-fired standby generator certified by the manufacturer to meet the Tier 2 standards.

The Caterpillar engine identified in this TSD has PM emissions that are lower than the CARB's 0.15 g/bhp-hr emission limit.[15] If a different make/model emergency standby generator is selected during detailed design for the project, a Tier 2 certified engine would be specified at time of purchase. Furthermore, PSE commits to use ULSD.

Ecology agrees with PSE that BACT for the proposed emergency standby generator is meeting the EPA NSPS for emergency compression ignition engine-generators and using ULSD (15 ppm) for the fuel. Annual operation for maintenance, testing, and training is limited to 275 hours. In addition, Ecology imposes an emission limits as shown in Table 16.

Table 16. BACT Summary for the Emergency Generator

Pollutant	BACT	Emission Limit	Compliance Method
CO (for SGT6-5000F4 turbine option only)	Use of ultra-low sulfur fuel, not to exceed 15 ppmvd fuel sulfur	3.5 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	• A written manufacturer supplied certification. • Maintaining the engine according to manufacturer's recommendations. • Recordkeeping of the engine run times, duration, and purpose of each use.
$PM/PM_{10}/PM_{2.5}$		0.20 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	
CO_2e		0.20 g/kW-hr, five-load weighted average using the procedures in 40 C.F.R. Part 89, Subpart E	Recordkeeping

[14] CARB, Staff Report: Initial Statement of Reasons for Proposed Rulemaking-Proposed Amendments for the Airborne Toxic Control Measure for Stationary Compression Ignition Engines, September 2010.
[15] CARB, executive Order U-R-001-0380-1 for the 2010 Caterpillar ACPXL 18.1 ESW engine family, August 30, 2010.

3.8. BACT for Start-Ups and Shutdowns

The BACT limits discussed in the previous sections apply to steady-state operation, which is after the turbines have reached stable operations, and the emission control systems are fully operational. BACT must also be determined for periods of combustion turbine start-ups and shutdowns. Frequent start-ups and shutdowns are a normal part of the operation of a peaking power facility. Emission rates during start-ups and shutdowns are highly variable, and turbine exhaust concentrations may be greater than those during steady-state operation, especially for combustion turbines with DLN combustors. This is especially true for CO, NO_X, and VOC since it is common for these concentrations to be higher during partial-load operation compared to normal operation. The reasons for increased concentrations are: (1) the turbines are less efficient when operating at low loads, (2) the exhaust temperatures are lower than during steady-state operations, which results in post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst to not function optimally at these lower temperatures, and (3) combustion air and turbine exhaust gas flow rates are lower. Thus, mass emissions can be minimized for a quick start turbine design.

Modern simple cycle gas turbine generators are designed to achieve significantly improved rapid responses to load changes on the electrical grid. A more rapid response helps improve system reliability and efficiency. Modern simple cycle turbines have inherently low start-up emissions because they can quickly come up to full operating load.

A review of the EPA's RBLC database and other sources did not identify any control technologies for simple cycle gas turbines specifically for the SUSD periods. Ecology is therefore establishing numerical emission limits on the quantity of emissions during each SUSD event while minimizing or limiting the SUSD duration (Table 17). These limits are calculated based on emissions estimates and start-up/shutdown operation profiles provided by the gas turbine vendors (i.e., General Electric and Siemens).

Table 17. Start-Ups and Shutdowns BACT

Options	SU/SD	Fuel	Max. Duration (Min.)	Max. # of SU/SD per Year	Emission (lb/event/unit)		
					CO	PM	H_2SO_4
GE 7FA.05	SU	Gas	30	144	---	9.2	5.8
		Oil	30	14	---	17	1.0
	SD	Gas	19	144	---	5.8	2.6
		Oil	17	14	---	9.6	0.4
GE 7FA.04	SU	Gas	30	144	---	6	8.0
		Oil	30	14	---	17	1.0
	SD	Gas	14	144	---	4	3.2
		Oil	14	14		9.6	0.4
Siemens	SU	Gas	35	144	1,347	4.8	7.2

Table 17. Start-Ups and Shutdowns BACT

Options	SU/SD	Fuel	Max. Duration (Min.)	Max. # of SU/SD per Year	Emission (lb/event/unit)		
					CO	PM	H_2SO_4
5000F4		Oil	38	14	1,462	15.6	1.0
	SD	Gas	17	144	443	2.4	3.6
		Oil	19	14	709	10	0.6
GE LMS100 (2 Units)	SU	Gas	30	240	---	3.3	3.7
		Oil	30	14	---	14.3	0.5
	SD	Gas	8	240	---	1.0	0.4
		Oil	8	14	---	4.7	0.05

In order to protect hourly air quality standards, the start-ups and shutdowns are limited to one per unit per hour, two per unit in a 3-hr period, five per unit in an 8-hr period, and five per unit in a 24-hr period. Furthermore, start-ups and shutdowns on distillate are limited to one per 24-hr period with the addition of up to four each on natural gas.

GHG emissions are a function of fuel consumption, which is minimal during start-ups and shutdowns compared to full load operation. The four simple cycle gas turbines proposed for the project are all capable of achieving fast start-ups and shutdowns, which reduces the effect of start-ups and shutdowns on the GHG emissions. SUSD emissions for GHG are included in the annual emission limitation for GHG and as such do not need to be separately specified.

3.9. Toxic Air Pollutants

PSD rules require the applicant to consider emissions of TAPs during the course of a BACT analysis, but specifically exempt all pollutants subject to regulation under Section 112 of the federal Clean Air Act from regulation under the PSD program.

The emissions of TAPs will be covered in the NWCAA NOC approval for this project.

4. AMBIENT AIR QUALITY IMPACTS ANALYSIS

4.1. Regulatory Requirements

For PSD, an ambient Air Quality Impacts Analysis (AQIA) is required for all pollutants that are emitted in significant quantities to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from the proposed major stationary source or major modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment.

The AQIA starts with preliminary modeling for each pollutant to determine whether an applicant can forego detailed analysis and preconstruction monitoring. If the projected ambient concentration increase for a given pollutant is below the PSD Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMCs) for each averaging period, no further analysis of the ambient impact is required for that pollutant.

For those pollutants with averaging periods that have impacts greater than the SIL, a full impact analysis is used to demonstrate compliance with NAAQS and PSD increments.

Typically, the AQIA includes an analysis of impacts to local areas that are within 50 kilometers (km) of the project, and a regional air quality impact assessment for impacts beyond 50 km. For projects in Washington State, this latter analysis usually includes impacts on Class I areas.

4.2. Modeling Methodology

Ecology is required to use dispersion models accepted in 40 C.F.R. §51, Appendix W, Air Quality Models. The AERMOD model (Version 09292) is the currently accepted model for assessing ambient air quality from industrial sources for distance out to 50 km. AERMOD is based on the Gaussian and planetary boundary layer concepts, designed for sources located in all types of terrain (flat, simple, intermediate, and complex) and for sources subject to aerodynamic building downwash. AERMOD has been used for this project to assess the AQIA in Class II areas within 50 km of the project site. A modeling protocol was submitted to Ecology and the Federal Land Managers (FLMs) on September 24, 2010. Additional amendments and correspondence with Ecology and the FLMs have been incorporated herein.

AERMOD was used to predict the increases in criteria pollutant concentrations due to the project emissions only. These impacts were then compared to the SILs to determine whether additional analyses would be required. The inputs to the model are discussed in detail in the permit application. Prior to submittal of the application, Ecology reviewed and accepted PSE's modeling protocol and has accepted the modeling results as presented in the application.

4.3. Estimated Max Emission Rates (Worst-Case Scenarios) for Modeling

Long-term emission rates used in the modeling were calculated as outlined in Section 2.2, and shown in Tables 3 and 5.

Short-term emission rates were developed based on the worst-case operating scenarios for each pollutant. These worst-case emission scenarios are dependent upon both the emission rate and the stack parameters under each scenario, which differs for each turbine option proposed. PSE Fredonia used a two-stage approach to develop worst-case scenarios for each turbine option. During the first stage (named "load check"), for each of the turbine options, only turbine operating emissions (excluding SUSD) are modeled for 1-hour impacts at the operating conditions of load, fuel, and ambient temperature for each turbine option with corresponding source parameters. Based on these load check results, a refined worst-case scenario for full modeling for each turbine option was then developed using a combination of worst-case load (that is operationally feasible for the time duration), and start-ups and shutdowns when they are operationally feasible for the time duration *and* have the potential to cause higher impacts due to increased emissions. The worst-case scenarios for each modeled pollutant are listed in Table 18.

The emergency generator is also included in the refined full modeling analyses. Only the location of the generator changes between the four turbine options because of site configuration requirements. The worst-case emissions for the emergency generator were modeled the same way for each of the options using the parameters shown in Table 19.

Table 18. Refined Modeling—Worst-Case Scenario Emissions for the Potential Turbine Options

Averaging Period	Turbine Stack Parameters				Emission Rate (lb/hr/unit)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
GE 7FA5							
Annual	145	800	120	23	9.76	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	87	23	36.80	---	Distillate; 50% load; 7°F; no SU/SD.
GE 7FA4							
Annual	145	800	127	21	9.85	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	102	21	37.60	---	NG at 3.48 gr/100 scf; 50% load; 7°F; no SU/SD.
Siemens SGT6-5000F4							
Annual	145	800	118	23	7.39	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	145	799	95	23	32.80	---	Distillate; 70% load; 88°F; no SU/SD.
1-hr	145	799	103	23	---	2173[a]	Distillate; 75% load; 7°F; 1 Distillate SU/SD.
8-hr	145	799	103	23	---	1203[a]	Distillate; 75% load; 7°F; 1 Distillate SU/SD over 1 hr, and additional 4 NG SU/SD over 8-hr period.
GE LMS100							
Annual	110	777	127	12	5.12	---	Annual NG and Distillate—all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; average temperature (51°F).
24-hr	110	800	129	12	18.52	---	Distillate 80% (combined for 2 units) use factor over 24-hr period; 90% use at 100% load; 88°F.
	110	800	113	12	2.83	---	Distillate 80% (combined for 2 units) use factor over 24-hr period; 10% use down to 75% load; 88°F; 1 Distillate SU/SD.

[a] The actual worst-case CO emission rates are lower than numbers here, because of the new 8 ppm CO BACT limit on distillate. For the modeling impact analyses, emissions were based on the PSE proposed 12 ppm CO BACT limit on distillate.

Table 19. Refined Modeling—Worst-Case Scenario Emission for the Emergency Generator

Averaging Period	Generator Stack Parameters				Emission Rate (lb/hr)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
Caterpillar C18							
Annual	50	994	146	0.833	0.00607	---	Distillate; full load; 500 hr/yr,[1] inclusive of 52 hr testing and maintenance plus potential emergency operation
24-hr	50	994	146	0.833	0.1063	---	Distillate; full load; 24 hr (full-time)
1-hr	50	994	146	0.833	---	1.063	Distillate; full load; 1 hr (full-time)
8-hr	50	994	146	0.833	---	1.063	Distillate; full load; 8 hr (full-time)

[1] Total operation hours for the emergency generator will be limited to 275 hr/yr. The emissions provided in this application and TSD are based on this annual value. However, for the modeling impact analyses, emissions were based on the conservative 500 hr/yr, *except* for the Diesel Engine Exhaust Particulate (TAP) impact analysis, which used the revised 275 hr/yr operation.

4.4. Modeling Results for Air Quality Impact Assessment

The highest predicted short-term concentrations and highest predicted annual averages predicted by the modeling are compared to the appropriate SILs and SMCs as tabulated in Table 20. $PM_{2.5}$ and PM_{10} (and CO for Siemens Options only) air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants (under worst-case scenarios: by ambient condition, operation (i.e., start-up, shutdown, normal), loads, emergency generator, etc.) are less than the applicable PSD levels.

Table 20. Criteria Pollutant Impacts for the Potential Turbine Options at Class II Areas

Pollutant	Averaging Time	Maximum Predicted Impacts (μg/m³)				SIL (μg/m³)	Over SIL?	SMC (μg/m³)	Over SMC?
		GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)				
CO	1-hr	---	---	110	---	2,000	NO	---	---
	8-hr	---	---	23	---	500	NO	575	NO
PM_{10}	Annual	0.007	0.007	0.004	0.02	1.0	NO	---	---
	24-hr	1.04	1.04	0.48	1.71	5.0	NO	10	NO
$PM_{2.5}$	Annual	0.007	0.007	0.004	0.02	0.3	NO	---	---
	24-hr	1.04[1]	1.04	0.48	1.149[1]	1.2	NO	2.3	NO

[1] When using the correct coordinates, maximum predicted impacts for GE 7 FA.05 $PM_{2.5}$ (24-hr) is 0.99 μg/m³ and for GE LMS100 $PM_{2.5}$ (24-hr) is 1.13 μg/m³. Both corrected values are not over SIL. See February 14, 2012, memo submitted by the applicant.

In addition, these maximum impacts occur at locations well within the receptor grids instead of on the borders, which would necessitate further grid analyses. As a result, no additional modeling was required to be performed on the finer grid spacing.

Based on these results, a full NAAQS analysis and an increment analysis were not required for any pollutant.

On December 19, 2011, Ecology was informed that the location coordinates provided for the combustion turbine stacks (for each turbine option) in the permit application were off by a few hundred feet to the east and south. Additional analysis was performed by PSE Fredonia, and approved by Ecology on February 10, 2012. PSE Fredonia demonstrated that the error did not significantly affect air quality modeling results presented in the original permit application. Therefore, the original analysis in PSE Fredonia's PSD permit application is sufficiently accurate to demonstrate compliance with air quality standards.

The following discussion in this section was added to the TSD as part of a response to a comment from the Sierra Club.

The background concentrations affecting the Fredonia Power Generating Station are:

Species	Background	SIL	NAAQS
$PM_{2.5}$ 24 hr µg/m^3	13	1.2	35
$PM_{2.5}$ annual µg/m^3	6	0.3	12
PM_{10} 24-hr µg/m^3	43	1.04	150
CO 1 hr ppm	1.323	1.11	35.0
CO 8 hr ppm	0.922	0.278	9.0
NO_2 1 hr ppb	33		100
NO_2 annual ppb	8	0.53	53

Sierra Club submitted the comment that "Ecology determined that the plant's CO, PM_{10}, and $PM_{2.5}$ impacts would not cause a violation of the NAAQS or the increments solely on the basis of a comparison between the facility's predicted impacts and the "significant impact levels" or "SILs." This conclusion is insufficient unless Ecology determines that the impacts, even if below the SIL, are not sufficient when added to background concentrations and impacts from other nearby facilities, to cause or contribute to a violation of the ambient air quality standards or the increments." The above table shows that background is very low compared to the NAAQS. Even if the project was projected to produce emissions to almost reach the SILS, the addition of a SIL to the corresponding background concentration would not approach exceeding the NAAQS. In addition, Ecology demonstrated that the maximum impacts occur at locations well within the receptor grids located on the facility's property rather than on the facility's boundary. If the maximum impacts had been found off the facility's property, further grid analyses would be required to be performed to ensure that ambient air would not be affected. As a result, the air analysis was considered complete, and no additional modeling was performed on the finer grid spacing. Ecology appropriately concluded that a full NAAQS analysis and an increment analysis were not required for any pollutant. Ecology found that the SIL and background levels are not close to violating one of the NAAQS. The impacts from other industrial facilities are minimal because the PSE facility is proposed to be located in a rural area with few industrial neighbors.

5. ADDITIONAL IMPACTS ANALYSIS

PSD regulations and guidance require additional impact analyses to evaluate the effects of the project's emissions on visibility, local soils, and vegetation in Class I and II areas, and the effect of increased air pollutant concentrations on flora and fauna in the Class I areas. The additional impact analyses are also used to evaluate the effect of the project on growth in the area surrounding the project.

5.1. Growth Analysis

PSE Fredonia facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington. According to 2009 census data, Skagit County experienced a total population growth rate of 16.1% between 2000 and 2009. Expansion of the FGS does not cause growth, but provides some of its power to the community it serves in Skagit County.

The construction of the project is expected to begin in 2013 and should take approximately 18 months to complete. The completion of the project will require approximately 200 temporary construction-related jobs, though there will not be 200 construction workers on-site for the whole construction period. The expanded facility will create two to four additional permanent jobs. The municipal and residential services currently provided in the surrounding communities will be adequate to support the proposed project. Therefore, potential negative impacts on local air quality and Class I area air quality associated with municipal and residential growth are not anticipated.

5.2. Soils and Vegetation Analysis

Project emissions that have the most potential to affect soils and vegetation are those that contain either sulfur or nitrogen. SO_2 and NO_X are not subjected to PSD review for this project because their emissions are less than their respective SERs. As a result, no deposition analysis was required, but this analysis was conducted and is included in the application.

5.3. Visibility Impairment Analysis

The local visibility impacts of the project should be negligible. Natural gas combustion does not typically produce any visible particulate emissions. The turbine exhaust stack emissions will typically be clear, and the opacity will be limited through the NWCAA NOC permitting process. This amount of opacity is normally just barely perceptible. Visibility impacts on more distant Class I areas (and, in a conservative manner, on the Mount Baker Wilderness Area (MTB), a Class II area) are discussed in the Air Quality Related Value (AQRV) analysis below.

5.4. Class I Areas Impacts Analysis

Federal (40 C.F.R. §52.21) and Washington State (WAC 173-400-117) PSD regulations require that the impact of a proposed facility on federal Class I areas be analyzed. Mandatory Class I areas are defined in the federal Clean Air Act, and are afforded the highest level of air quality protection under the PSD rules. They include most national parks, national wilderness areas, and national memorial parks. WAC 173-400-030(16) lists the Class I areas in Washington State. North Cascades National Park (NCNP), Olympic National Park (ONP), Glacier Peak Wilderness (GPW), and Alpine Lakes Wilderness (ALW) are the only Class I areas near this project site. In addition to these Class I analyses, per request of the United States Forest Service (USFS), visibility and deposition was evaluated for MTB, which is a Class II protected area located approximately 41 km from the project site.

In general, the impacts analysis includes an assessment of increment consumption and impacts to AQRVs in Class I areas. The objective of the AQRV analysis is to demonstrate that air emissions from the proposed project would not cause or contribute to a significant impact on visibility, regional haze, total nitrogen (N), or total sulfur (S) deposition in any of the specifically modeled Class I areas. The National Park Service (NPS) and USFS are the FLMs who have the responsibility of ensuring that AQRVs in the Washington Class I areas are not adversely affected.

5.4.1. Criteria Pollutant Maximum Predicted Concentrations in Class I Areas

Per request of USFS and Ecology, the Class I area impact analysis was performed for MTB, a Class II area located less than 50 km from the proposed project. Impacts were evaluated using the results of the AERMOD modeling discussed in Section 4.

Table 21. Criteria Pollutant Impacts for the Potential Turbine Options at MTB

Pollutant	Averaging Period	Maximum Predicted Impacts (µg/m^3)				Class I SIL (µg/m^3)
		GE 7FA.05	GE 7FA.04	Siemens SGT6- 5000F4	GE LMS100 (2 Units)	
PM_{10}	Annual	0.001	0.001	0.001	0.001	0.08
	24-hr	0.041	0.041	0.037	0.055	0.27
$PM_{2.5}$	Annual	0.001	0.001	0.001	0.001	0.06
	24-hr	0.041	0.041	0.037	0.055	0.07

This modeling indicates (as shown in Table 21) that the $PM_{2.5}$ and PM_{10} concentrations are well under their respective SILs. Because all the Class I areas are a further distance from the facility in relation to MTB and the impacts at MTB are all well below their respective SILs, it is safe to conclude that all Class I areas within 100 km of the project have impacts below the SILs. Therefore, no further analysis is required, and additional dispersion modeling using the accepted guideline model was not performed.

5.4.2. AQRV Screening Analysis

The NPS, USFWS, and the USFS released revised guidance *Federal Land Managers' Air Quality Relative Values Work Group (FLAG) Phase 1 Report –Revised (2010)* (Natural Resources Report NPS/NRPC/NRR – 2010/232, October, 2010; 75 FR 207, October 27, 2010). This final version of updates, initially issued in 2008, includes a threshold ratio of emissions to distance (Q/d), below which the services have determined a detailed AQRV review is not required. The FLAG document contains the following decision process:

If Q (tpy)/d (km) is less than 10, no AQRV analysis is required, where:

- Q is the emission increase of SO_2, NO_X, PM_{10}, and H_2SO_4 mist combined in tpy.
- d is the nearest distance to a Class I area in km.

If Q/d is less than 10 for a Class I Area, then presumptively, there is no adverse impact and a project "screens out" of a Class I AQRV analysis. If Q/d results in a value above 10, a Class I analysis is required.

Q for use in the above formula was based on the project's maximum 24-hour emission rates, and converted to an annual emission rate assuming full-time operation of 8,760 hours. A calculation of Q was developed for each turbine option. Table 22 provides the estimates for each option of both the specific pollutant emission rates, and the total emissions, Q. The estimates include 24 hours of emergency engine use. These values are then divided by the distance to the nearest Class I area, which is NCNP at 69 km from the PSE project site. Using these conservative estimates for emissions, all of the project's options have a Q/d value below 10 for each Class I area. Therefore, the FLMs do not require any additional AQRV analyses. However, a full AQRV analysis was still conducted for the Class II MTB. Details about this analysis are available in the permit application.

Table 22. AQRV Q/d Screening Analysis

	Turbine Option			
	GE 7FA.05	**GE7FA.04**	**Siemens SGT6-5000F4**	**GE LMS100 (2 Units)**
Maximum Emissions (lb/hr) on a 24-hr Basis[1]				
NO_X	52	30	52	39
PM_{10}	48	46	40	54
SO_2	10	9	9	9
H_2SO_4	22	19	23	17
Sum of Emissions Prorated to Full-Time Annual Basis (tpy)[2]				
Q	578	458	543	517
AQRV Screening[3]				
Q/d	**8.38**	**6.64**	**7.87**	**7.49**

[1] Emission rates include emergency generator operation.
[2] Annual emissions (Q) assume 8760 hr at maximum 24-hr lb/hr emission rate.
[3] Distance to nearest Class I area is 69 km (NCNP).

6. ENDANGERED SPECIES ACT

Pursuant to Section V.A. of the Agreement For The Delegation Of The Federal Prevention of Significant Deterioration Program from the United States Environmental Protection Agency to the Washington State Department of Ecology, dated November 17, 2011, Ecology shall not issue a PSD permit until EPA has notified Ecology in writing that EPA has satisfied its obligations, if any, under Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1531 et seq., and 50

C.F.R. Part 402, Subpart B (Consultation Procedures), and with Section 305(b)(2) of the Magnuson-Stevens Fishery and Conservation Act (Magnuson-Stevens Act, MSA), 16 U.S.C. § 1801 et seq., 50 C.F.R. Part 600, Subpart K (EFH Coordination, Consultation, and Recommendations), for federal PSD permits regarding essential fish habitat. Therefore, the final PSD permit will not be issued for this project until EPA has notified Ecology that this consultation has been completed.

On December 13, 2012, the EPA notified Ecology that they have satisfied their obligations under the Endangered Species Act and the Magnuson-Stevens Act relative to this permitting action. No further ESA or MSA consultation was undertaken relative to this action.

7. STATE ENVIRONMENTAL POLICY ACT (SEPA)

Under Washington State rules, a final PSD permit shall not be issued for a project until the applicant has demonstrated that SEPA review has been completed for the project. The Skagit County is the lead agency for SEPA for this project.

On February 3, 2012, PSE submitted a "Determination of SEPA Compliance" to Skagit County. The county explained that the proposed expansion and changes in air quality emissions at PSE Fredonia have been addressed through land use and environmental reviews. The county concluded that "total site emissions of VOCs with the proposed project will be well below the maximum level established in the 1991 [Environmental Impact Statement, EIS]. No further study of air quality emissions will be required by Skagit County . . . ."

Ecology concludes that the applicant has adequately demonstrated compliance with SEPA requirements.

8. AGENCY CONTACT

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Appendix A. Sierra Club's Comments

SIERRA CLUB
FOUNDED 1892

April 17, 2013

Via Email and Certified U.S. Mail

Marc Crooks
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RE: Fredonia Power Generating Station –Permit No. PSD-11-05

Dear Mr. Crooks:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 21,000 members in Washington. The issues addressed below regarding the proposed Prevention of Significant Deterioration (PSD) permit for Puget Sound Energy's (PSE) Fredonia Power Generating Station (PSD-11-05) are based off of the January 30, 2013 Technical Support Document (TSD) prepared by the Washington State Department of Ecology Air Quality Program (Ecology) and the proposed permit.

Sierra Club appreciates the opportunity to provide these comments to ensure that any electric generating units planned for construction at the Fredonia site are consistent with the most rigorous air quality pollution control measures required by law. As a preliminary matter, Sierra Club notes that the permit application and the TSD lack documentation for several critical assertions needed to establish appropriate permit terms and conditions. This omission is a major concern throughout the application and the TSD for the proposed permit. For example, Ecology copies PSE's Table 5-5 into the TSD as Table 14 and includes calculations that are neither sourced nor critically reviewed by Ecology. This lack of supporting data impedes meaningful review by Ecology or the public. Ecology should provide all worksheets in Excel or other accessible formatting to the public. Similarly, PSE's load forecasts and dispatch modeling must be provided to verify several critical operating assumptions for the proposed addition to Fredonia.

1. GHG BACT Requires a GHG Emissions Rate Limit Achievable by the Most Efficient Turbine Model

New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a CO_2e basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy CO_2e, are subject to PSD permitting requirements even if they do not significantly increase emissions of any other PSD pollutant. The proposed Fredonia facility would add one or two new generating turbines and is expected to emit GHGs at a rate greater than 100,000 tpy CO_2e; therefore, the project is subject to PSD review for all pollutants emitted in a significant amount.

PSE requests approval to construct one of the following four options:

- One (1) General Electric (GE) 7FA.05 frame turbine, rated at 207 MW
- One (1) GE 7FA.04 frame turbine, rated at 181 MW
- One (1) Siemens SGT6-5000F4 frame turbine, rated at 197 MW
- Two (2) 100 MW GE LMS100 aero derivative turbines (combined rating of 200 MW)

Ecology proposes to allow PSE to choose any of these four options, regardless of their relative greenhouse gas (GHG) emission rates. The proposed permit sets four different GHG emission rate limits for each option based on the heat rate at full load for each design. (TSD, Table 14 at p.34.) Ecology justifies this approach of setting different emission limits because the permit also sets different maximum fuel use limits for each turbine design – and therefore the annual tons-per-year of GHG emissions – differs (i.e. the most efficient unit has the highest maximum fuel use limit).[1] However, this approach is not appropriate because it confounds a maximum limit on the potential to emit with the BACT emissions rate analysis.

This proposal does not comply with PSD permitting requirements because the relative efficiency of the four turbine designs is different, and therefore the GHG emission rates are different. Ecology cannot set different emission limits for whichever turbine design the applicant chooses, as the draft permit purports to do, because the emission reduction achievable through a clean production process is part of the BACT definition. Rather, the most efficient turbine design must be used as the basis for the BACT limit unless the applicant demonstrates a sufficient site-specific basis to reject that technology. Here, the applicant cannot make this claim, and, in fact, PSE indicates that it may choose to use the most efficient turbine technology. **The PSD permit must require PSE to meet a GHG emission rate (1,138 lb-CO_2e/MW-hr) that is achievable by the most efficient unit, the GE LMS100.**[2]

[1] There is no support in the TSD for requiring different maximum fuel limits. PSE's application assumes, without explanation, that the LMS 100 units will run at a 33% capacity factor, excluding startup and shutdown, while other units run at a 26% capacity factor. In addition, the annual emissions are based on the "worst-case" operating scenarios that would result from the maximum operating limits. (TSD at p.7.) As a result, the comparison between different turbine design estimates of tons-per-year GHG emissions is distorted by the unequal worst-case operating scenarios.

[2] Proposed Permit at §V(D)(1)(a)(iv). The total limit is higher than the combustion turbine's CO_2 emission rate because Ecology incorporates emissions of CH_4 and N_2O using the emission factors from previous source testing at PSE's Sumas and Mint Farm Generating Stations in 2009. (TSD at pp. 9 and 36.)

Clean Air Act § 165(a)(4) requires Fredonia to install the Best Available Control Technology (BACT), which is defined as "an emissions limitation … based on the maximum degree of reduction for each pollutant subject to regulation under the Act…" 42 USC 7479(3); 40 CFR 52.21(b)(12). Ecology recognizes that for GHG emissions, the efficiency of the combustion unit is a primary factor that determines GHG emission rates. "GHG emissions are directly related to minimizing the quantity of fuel required to make electricity." (TSD at p.32.) In this case, the CO_2e emission rate of the LMS-100 design is 1,052 lb/MW-hr for the turbine. (TSD at p.33, Table 13.) The least efficient unit, the GE 7FA.04, has a CO_2e emission rate that is 13.2% higher at 1,191 lb/MW-hr. This difference would roughly equate to 34,194 tons annually, assuming 2,000 operating hours (23% capacity factor) for each unit.[3]

a) <u>The Permit May Not Set a Weaker GHG Limit Based on Alternate Operating Scenarios.</u>

The LMS 100 units are clearly more efficient than all of the other simple-cycle turbine options contemplated by the proposed PSD permit. Ecology fails, however, to base its proposed BACT limit on the lowest GHG emission rate among the available options. Instead, Ecology concludes that all four options are BACT because "Ecology considered engine efficiency together with proposed operating scenarios associated [with] all four options during BACT analysis." (TSD at p.35.) There is no basis under the law for selecting a higher emitting technology based on different operating scenarios. The BACT requirement is defined as "the maximum degree of reduction for each pollutant." 42 USC 7479(3). PSE does not suggest that the LMS 100 units are infeasible or inconsistent with the purpose of the project. Since PSE states that the technologies that would meet its needs range from 185 to 215 MW,[4] the 199.7 MW LMS100 can meet that need. (TSD, Table 14, at p.34.) Therefore, the top-down BACT analysis requires Ecology to select the lowest emitting technology as the basis for setting the BACT emission limit. In this case, that technology either the LMS 100 or a fast start CCGT unit, such as those offered by GE and Siemens.

Ecology asserts that a weaker GHG emission rate limit for different turbines is appropriate because differences in annual operating scenarios and operating hours mean that "the least efficient make and model is not necessarily the highest annual emitting option." (TSD at p.35.) This conclusion is contrary to the BACT requirement that Ecology set the emissions limit based on the maximum degree of pollution reduction achievable. Ecology's approach conflates the issue of the BACT analysis with the issue of setting maximum operating limits under worst-case conditions. Changing the maximum operating scenarios for higher emitting units is not a valid justification for weakening the GHG emissions limit. Doing so would allow an applicant to alter its estimated operating hours to avoid a more stringent emissions limit and invite gaming of the BACT analysis. Here, the most efficient technology <u>is</u> the best available technology, and the BACT limit, in terms of lb CO_{2e}/MWh, must reflect this efficiency.

Ecology's contention that GHG emissions limit should be weakened because of net annual GHG impacts under different operating scenarios is also unsupported. The total annual fuel use

[3] Table 14 assumes a capacity factor of 7.5% and a corresponding CO_2e tpy difference of 9,101 between the LMS 100 and the 7FA.04. Sierra Club's estimate of emission difference at 2000 hours (23% capacity factor) is derived from Attachment A.

[4] These figures reflect the most current ratings for the units identified in the TSD, as published in the 2011-2012 *Gas Turbine World Handbook*, published by Pequot Publishing, Inc. ("GTW Handbook")

of the LMS 100 is much higher than the other units, despite the fact that it is the most efficient unit. This skewed estimate is the result of the assumption that the LMS 100 would operate more hours than the other units. The record does not include load forecasts or dispatch modeling supporting the assumption that the various turbines would be operated differently, and the respective permit maximum limits do not require that the chosen turbine be operated according to these hypothetical scenarios. To the contrary, the calculations in Table 14 of the TSD assume that all of the turbine designs operate at a much lower 7.5% capacity factor. Ecology must explain why the LMS 100 turbine designs would practically operate so differently than the other turbine designs. In particular, Ecology must explain in much more detail how it derived the annual maximum fuel limits for each turbine design.

The Fredonia units will presumably be dispatched as needed based on their economic loading order.[5] Even if the LMS 100 units were dispatched more frequently or at greater generating capacities than the other options, it would be because of their higher efficiency compared to other resources. In other words, Ecology's theory undermines BACT because it assumes that the most efficient process is more competitive in the market and therefore operates more often, and emits more, and so should not be the basis for BACT. Even assuming that it is appropriate to consider how the plant will operate within the market, Ecology should not look only at this plant in such an analysis. Any increased operations of a more efficient technology chosen for this plant would likely displace generation from other, less efficient, peaking units within PSE's system.[6] In short, GHG emissions from peaking units in the PSE system as a whole will likely be lower if the LMS 100 models are employed as compared to the other units proposed. The LMS 100 units are the lowest emitting units on a per MW-hour basis, and therefore that technology must be considered as BACT for GHG.

b) BACT Requires an Emissions Limitation Based on the Maximum Degree of Reduction Available.

PSE's application argues that, "EPA has never taken the position that BACT requires an applicant to purchase a particular make and model of turbine engine for an electric generating facility."[7] This argument misses the point of the BACT requirements. BACT does not select a technology, it sets a limit. EPA (and other permitting agencies) may not require a specific make and model of technology, but that does not mean that a BACT limit does not affect the range of buying options available to a facility. The NSR Manual provides: "The reviewing authority…specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable…" (NSR Manual, p.B.2.) In this case, the maximum degree of reduction is a combustion turbine achieving 1,052 lb CO_2e/MW-hr. Turbine vendors that can meet that limit are free to compete for PSE's business. Just as a BACT limit for another pollutant may be based on the most efficient scrubber design, scrubber vendors who can achieve sufficient emission reductions can compete for that contract. This feature of the BACT program has been remarkably successful in encouraging development of more effective pollution controls for over 40 years.

[5] Neither the permit nor the TSD discuss the results of any dispatch analysis. To the extent such a study informed the BACT analysis, it should be included in the TSD.
[6] It is possible that more efficient combined cycle units or renewables could be displaced, but there is no evidence in the application or the TSD suggesting that the proposed peaking units at Fredonia would ever displace lower-emitting units.
[7] Application, Appendix H, p. 5-16.

Furthermore, to the extent that Ecology implies that EPA does not establish BACT limits for GHGs based on turbine efficiency that might exclude some turbine designs, Ecology is incorrect. Turbine efficiency is clearly an important factor that EPA considers in its BACT analyses. The TSD identified the York Plant Holding project considered by Pennsylvania DEP. (TSD at p.33.) EPA Region 3 submitted the following comments on the proposed PSD permit: "The permit record should be able to show that the most efficient turbine model is chosen for the proposed project, or it should justify why a turbine with a lower efficiency was selected."[8] Similarly, Region 9's final PSD permit for the proposed Pio Pico Energy Center considered a proposed LMS 100 turbine design, concluding that "this [turbine efficiency] is at the high end of the efficiency range for gas turbines of this size category, thus we believe that the applicant's proposal is consistent with the BACT requirement to use highly efficient simple-cycle turbines."[9] It is entirely appropriate, and in fact necessary, to consider specific makes and model of turbine designs when determining the BACT emission rate limit.[10]

c) <u>The TSD's Analysis of Incremental Emission Reduction Costs Does Not Comply with BACT Requirements.</u>

The incremental cost difference between the different turbine options does not provide a reasonable basis to reject the lowest achievable GHG BACT emission limit. The TSD states, "The analysis shows that further CO_2e reductions would cost between $710 and $4,660 per ton of CO_2e removed." (TSD at p.34.) This calculation compares the relative CO_2e emissions of all turbines operate at a 7.5% capacity factor to the overall fixed and variable cost of operating each unit at that capacity factor. Ecology then concludes that this cost range is "in excess of costs that have been considered 'achievable' in other GHG BACT analyses…" (TSD at p.34.) This conclusion fails to comply with the requirements for rejecting a feasible technology based on a determination of adverse economic impact.

Step 4 of the BACT analysis considers the energy, environmental, and economic impacts of each feasible control option. (NSR Manual, pp. B.26-B.53.) The presumption is that the highest ranked feasible control technology is the basis for the BACT limit unless there is a specific determination that cost and impacts borne by the specific source in question are disproportionately higher than other sources in the same category. (NSR Manual, p.B.29.) Ecology has not determined (nor could it determine) that the cost to use the most efficient turbine at the Fredonia plant is any more expensive, on a cost per ton basis, than any other facility using that technology.

Moreover, as noted in the TSD, several permitting agencies have determined that the most efficient natural gas turbine design is the appropriate basis for the GHG BACT limit. (TSD at pp.29-30.) For example, as noted above, in considering a simple cycle natural gas turbine for the York Plant Holding project, which Ecology specifically cited in the TSD (TSD at p.33), Pennsylvania DEP expressly found that the most efficient simple-cycle turbine is BACT: "Even though the applicant wants to retain the ability to purchase any of the three turbines for purposes

[8] November 1, 2011 Letter from Kathleen Cox (EPA Region 3) to William Weaver (Pennsylvania DEP), (available at: http://www.epa.gov/nsr/ghgdocs/20111101york.pdf).
[9] PPEC Fact Sheet and Air Quality Impact Report, p. 20, (available at: http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0978-0017). Sierra Club is currently appealing this permit to the Environmental Appeals Board.
[10] *See, EPA PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, pp. 21, 29-30 (available at: http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf).

of maintaining a business advantage, in terms of heat rate, the GE LM6000 is the most efficient turbine and the GHG emission rates are developed based on the efficiency of that turbine."[11] The BACT determination for the York Plant Holding project rejected the approach that Ecology seeks to implement here: Pennsylvania DEP set the emission limit based on the most efficient turbine design rather than allowing the applicant to choose among several different GHG emissions limits for each design.

There is no evidence in the TSD or the application indicating that installing and operating the LMS 100 turbine design would cause uniquely excessive costs at Fredonia compared to other electric generating facilities. Ecology therefore has no basis to reject the most efficient and lowest GHG emitting turbine design based on adverse economic impacts.

a) The TSD's Analysis of Incremental Emission Reduction Costs is Unsupported and Incorrect

As noted above, the incremental cost analysis is not an appropriate reason to exclude the more efficient turbine design as BACT because there is nothing unique about the Fredonia facility that would make installation of the LMS 100 units disproportionately more expensive than at comparable facilities. However, even if the incremental cost analysis were valid, the calculations included in the TSD are incorrect.

Table 14 of the TSD includes the cost effectiveness analysis of the different turbine models. (TSD at pp. 34-35.) The LMS 100 is the smallest unit and therefore, like other smaller units, the capital cost per MW is somewhat higher than larger units – approximately $300 /kW for the LMS 100 compared to $230/kW for several 200MW units. However, the LMS 100 is about 13% more fuel efficient than the other units proposed by PSE. This fuel efficiency will offset the additional capital costs if the unit operates at sufficient capacity factors. For purposes of setting annual operating hours (and corresponding fuel use) Ecology assumes that the LMS 100 units may run up to 2,880 hours per year, and the proposed permit sets a fuel limit based on 2,880 hours per year. (TSD at p.5.) However, the "calculation" for incremental cost analysis is based on an assumption that the units will only run 630-657 hours per year. (TSD at p.34.) PSE cannot have it both ways. Even if the incremental cost analysis were a valid method of excluding more efficient turbines, which it is not, the calculations in the TSD unfairly bias the result against the more efficient but smaller LMS 100 turbines by assuming a capacity factor of only 7.5%, which is insufficient to allow the more expensive but more efficient turbines to recover their higher capital cost through more efficient and lower cost operation. If PSE plans to operate the new Fredonia units at only 7.5% capacity factor, then the permit's operating hours and fuel usage should reflect those estimates.[12] Instead, PSE uses one set of operating assumptions to calculate the "incremental cost" of more efficient turbines, and another set of operating assumptions to set their maximum operating limits in the permit. The calculation to support the BACT analysis must be consistent with the actual permitted conditions, and therefore any determination of adverse economic impact must be based on the permitted fuel usage/hours of operation.[13]

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[11] Attachment B, Pennsylvania Department of Environmental Protection, Sept. 6, 2011 Plan Approval Review Memo, York Plant Holdings, LLC, Plan Approval No. 67-05009C, p.13.
[12] In 2009 units 3 and 4 at Fredonia operated for 903 and 882 hours respectively. *See*, EPA Air Markets Program data www.ampd.epa.gov, visited April 13, 2013.
[13] *See, e.g.*, NSR Manual at p.B.68 (citing an example where cost effectiveness calculation considers permitted operating hours as the basis for establishing a disproportionate cost impact for SCR).

The TSD and PSE's application also do not provide any justification for the "all-in" capital expenses for the different turbine designs.[14] New plants can have a large disparity in capital costs, but many of these costs are related to site specific issues, such as the need to drive pilings for foundations, that have nothing to do with the particular turbine that is being installed. In this case, PSE does not break out the different turbine capital costs compared to other site-related costs. However, it is very unlikely that all of the capital expense differences are due only to the model of turbine selected. For example, PSE's application asserts that the difference between the LMS 100 and the GE 7FA.04 is \$94 million. (TSD at p.35.) However, this \$94 million is substantially **more than the actual cost of the two LMS units.** In other words, even if the GE 7FA.04 turbines were free, the difference in cost between the LMS 100 turbine and the GE 7FA.04 turbine would not be as high as the application purports. The GTW Handbook cites the cost of LMS 100 turbines at \$300/kW (\$60 million for two units), and a study prepared for New York City (as a purchaser) lists the cost at \$35 million for one unit (or \$70 million for two).[15] Ecology must reconcile how PSE's application concludes that the LMS 100 units cost \$94 million more than the GE 7FA.04 units when the cost of the LMS 100 turbines is only \$60-70 million.

Sierra Club examined three operating scenarios:[16] 2880 hours of operation; 2000 hours of operation; and 1,000 hours of operation. In each instance, the LMS100 demonstrated the lowest combined cost for recovery of the capital cost of the equipment, the fuel cost and the cost maintenance.[17] **Under these assumptions, there is no added cost to achieve the additional CO_2 reductions associated with the LMS 100.**

2. <u>Hour of Operation for Peaking Unit(s) are Too High</u>

Ecology based its emission calculations on hours of "standard" peaking mode operations, plus start-ups and shutdowns. (TSD at p.12.) However, the proposed permit sets maximum operating hours based on annual fuel use. (Proposed Permit §VII(A)(3) at p.12.) Setting maximum operating hours based on total fuel usage increases the total hours of operation because the calculations assume a compliance margin for hours of operation. In practice, the units will operate much more efficiently, and therefore setting a maximum fuel limit would result in even higher annual operating hours than the 2,880 and 2,280 in the proposed permit. In addition, Ecology provides no basis for the underlying operating scenario assumptions that it makes. For example, despite being the most efficient unit, the LMS 100 has the highest maximum annual fuel use. (TSD at p.12.) The Proposed Permit includes an additional 96 start-ups for a total of 240 at **<u>each</u>** LMS 100 unit, compared to 140 startups for the other units. (Proposed Permit at p.13; TSD at p.10.) There is no support in the TSD or in the application for the difference in operating scenarios between the LMS 100 and the other turbine designs. Nor is there any apparent basis for these assumptions. Even if PSE plans to change its dispatch depending on the unit selected, then that information – including any relevant dispatch studies – must be included in the public record. Otherwise there is no basis for, and no way for the public

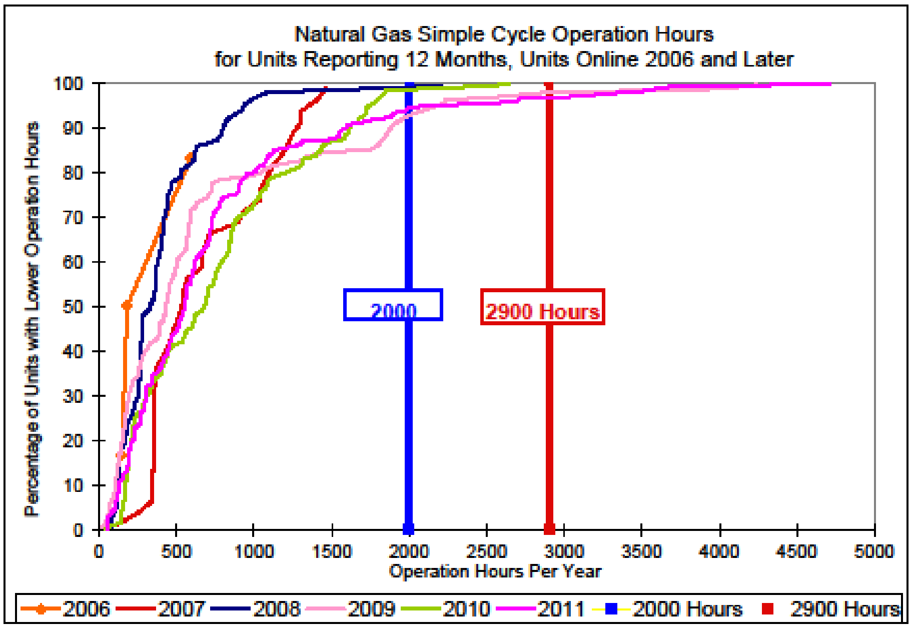
[14] TSD at p.35; Application, Appendix H at p.5-17.
[15] *Capacity Expansion Study For The Gowanus and Narrows Generating Stations*, Burns and Roe Enterprises, Inc October 19, 2006, p.13. (available at: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/ncapacity.pdf)
[16] Sierra Club relied on figures that reflect the most current ratings for the units identified in the TSD, as published in the 2011-2012 *Gas Turbine World Handbook*, published by Pequot Publishing, Inc. ("GTW Handbook").
[17] Attachment A (showing Sierra Club calculations).

to evaluate, why the proposed permit assumes that some designs would be operated differently than other designs at the same proposed facility.

a) Peaking Units Operate Less than 2000 Hours Annually

The TSD states that the Fredonia project must "respond to rapidly changing and often short-term peak power demands on PSE's system." (TSD at p.31.) However, the annual operating hours for all of the proposed units are much higher than typical peaking units. The available data show that almost all simple cycle combustion turbine units have low operating hours – but they also appear to show that a few large simple cycle units have high capacity factors. The TSD assumes that the LMS 100 would operate 2,880 hours per year excluding startup and shutdown, while the remaining units would operate 2,280 hours per year. (TSD at p.5.) This equates to capacity factors of 33% and 26%, respectively. The histogram in Figure 1 shows that the annual operating hours in the proposed permit are too high. The "knee in the curve" for these data appears to be below 2000 hours for 2011 (the most favorable[18] year for industry), thus showing that operation greater than 2000 hours is not consistent with the normal operation of simple cycle units.

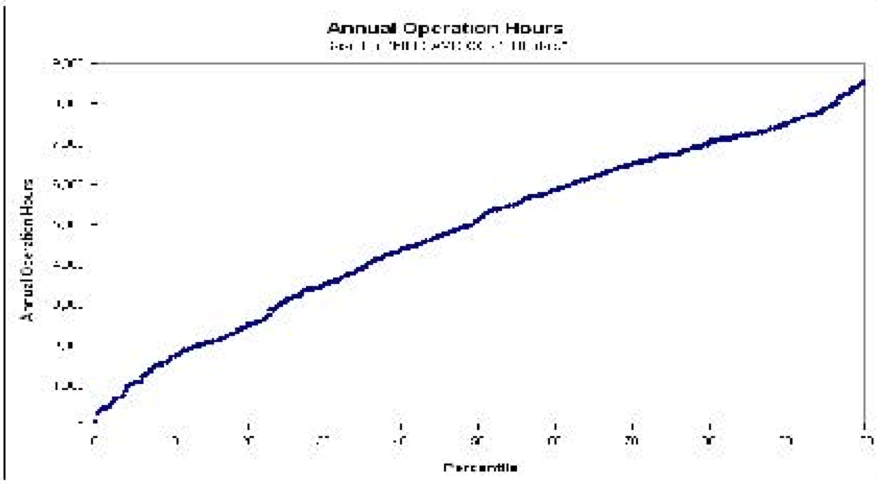
Figure 1. Hours of Operation for Combustion Turbines, by Year[19]



[18] For 2008, it is closer to 1100 hours.
[19] First year of operation 2006 or later, as determined by earliest occurrence of CAMD CEMS data. This data is included in electronic format submitted to Ecology via email as Attachment C.

We note that even 2000 hours of operation may represent simple cycle units that are in intermediate load rather than peaking operation, especially if such use is seasonal. We also note that there are a substantial number of combined cycle units that are designed for intermediate load applications but that may have limited hours of operation because of market conditions. Eighty-two of the 592 recently constructed combined cycle units in the EPA CAMD data set, Figure 2, operate less than 2000 hours per year; 143 of those units operated less than 2900 hours per year.

Figure 2. Hours of Operation for Combined Cycle Units



These data suggest that an hour of operation assumption above 2,000 hours does not sufficiently differentiate peaking from intermediate-load units. Intermediate units may operate seasonally, but for many hours at a time once started up. Such intermediate units are seasonal or load following, and these units are not true peaking units. In the proposed permit, Ecology must set the operational hours (and corresponding fuel limits) based on the characteristics of a peaking unit because it expressly rejected consideration of combined cycle units on the grounds that PSE needed the Fredonia project for "peaking applications." (TSD at p.31.) If PSE plans to operate Fredonia as an intermediate resource rather than a peaking resource, then the BACT analysis must fully consider combined cycle units as a feasible alternative.

Industry practice provides what appears to be the most useful definition of a peaking unit. Rather than the total hours per year of operation, General Electric defines "peaking" units in terms of an average hour of operation per startup. GE Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It then defines peak load as operation at 1250 hours per year with five hours per start.[20] Ecology should set the maximum operating

[20] Brooks, F., GE Power Systems, *GE Gas Turbine Performance Characteristics, GER-3567H*, p.14 (available at: http://www.muellerenvironmental.com/documents/GER3567H.pdf.)

hours for the Fredonia plant based on typical peaking units operating hours of 2,000 hours per year with limits on the number of hours per start, to ensure that the proposed simple cycle turbines are used as true peaking units rather than as base load or intermediate load units.[21] If PSE plans to operate Fredonia for more than 2,000 hours per year, then such use should be considered intermediate or load following and the GHG BACT analysis must consider alternative technologies, such as combined cycle, that can operate more efficiently and therefore at lower GHG emission rates. If PSE plans to use the Fredonia plant as a true peaking facility, then the permit's limits should reflect the expected maximum operating hours of a peaking plant and the limited hours of operation per start, rather than the inflated hours of 2,880 and 2,280 hours for the proposed simple-cycle turbines.

3. Exclusion of CCCT's is Inappropriate

Even if the permit maximum annual fuel limits are adjusted to reflect a true peaking unit, Ecology must provide support for its conclusion that more efficient combined-cycle units are incapable of meeting the needs of a peaking facility. The data in Figure 2 above indicate that many combined cycle units operate at less than 2,000 hours per year, which suggests that those units may operate as peaking facilities.

Ecology proposed a fuel limit equivalent to 2,880 hours of full load operation for the LMS 100 units and 2,280 hours of operation of the other units. The proposed permit also has different limits for the number of starts (240/144) for these units. (TSD at p.10.) As discussed above, these operating limits exceed typical peaking applications. Nevertheless, Ecology rejected combined-cycle turbine units because "[s]imple cycle combustion turbines are best suited, and more cost-effective for peaking applications." (TSD at p.31.) Ecology further appeared to agree with PSE's conclusion that "fast start CCCT are unproven technology" that neither Siemens nor GE have "commercially constructed and operated a fast start CCCT." (TSD at pp. 31-32.) This conclusion is unsupported and factually incorrect.

Fast start CCCTs have been used in peaking applications since 1989, including, *inter alia*, the Henrietta Plant in California.[22] A consultant's report prepared for the City of Yorba Linda, CA, identifies 44 existing or planned fast start CCCTs that range in size from 5 MW to 292MW.[23] More recently, NRG Energy, Inc. signed a contract in 2010 for one of the most recent advanced designs in the size range of the Fredonia plant - a Siemens Flex Plant 10 design – at the El Segundo Plant in California.[24] The Siemens Flex Plant 10 is designed to serve the peaking power market and has qualified for the non-spinning reserve market.[25] Construction of each of two 275 MW power islands at the El Segundo Plant is expected to be complete in August,

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[21] To provide PSE with a measure of flexibility, while still distinguishing between seasonally operated intermediate-load units and peaking units, we recommend that the GE norm of 1250 hours per year be relaxed to 2000 hours per year.

[22] http://www.energy.ca.gov/2010publications/CEC-800-2010-014/CEC-800-2010-014.PDF

[23] Cole, Jerold *Anaheim Canyon Power Project: Combined Cycle versus Simple Cycle Peaking Power Plant Configuration* (2009), Docket No 07-AFC-9 (available at: http://www.energy.ca.gov/sitingcases/canyon/documents/intervenors/2009-05-26_City_of_Yorba_Linda_Comparison_of_Combined-Cycle_vs_Simple_Cycle_TN-51684.pdf).

[24] http://www.elsegundorepowering.com/

[25] http://www.energy.siemens.com/co/en/fossil-power-generation/power-plants/gas-fired-power-plants/combined-cycle-power-plant-concept/scc6-5000f-1x1-flex-plant-10.htm

2013.[26] This unit employs the same SGT6-5000F turbine that is one of the options identified by PSE. While it has a slightly larger capacity than the GE 7FA.05 (275 MW for the FlexPlant 10 compared to 215 MW for the GE unit), there is nothing in the record suggesting that this larger capacity would render the FlexPlant 10 as "infeasible" for a large electricity provider such as PSE.

Ecology's rejection of fast start CCCT technology on the basis that it would require the project to be fundamentally redefined is unsupported by the TSD and the application. As noted above, fast start CCCT's are capable of meeting peaking applications. The proposed permit assumes a very high annual maximum operating usage. As the total operating hours of the units increase, a combined cycle unit will become more cost effective. Unless the permit contains a limitation on the hours of operation that more clearly reflects the operation of a peaking unit, Ecology must fully analyze whether a fast start CCCT could economically meet the requirements of the project. Ecology cannot simply reject CCCTs as technologically infeasible in step 2 of the BACT analysis when there is evidence that combined-cycle units can meet the ramping requirements of facilities that operate more than 2000 hours per year. Ecology must include combined cycle as a feasible control option in the BACT analysis and consider its cost effectiveness in later steps of the top-down BACT analysis.

4. The TSD Does not Provide Sufficient Support for the Elimination of Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is a technology that involves capture and storage of CO_2 emissions to prevent their release into the atmosphere. (TSD at p.29.) Ecology appropriately considered CCS from gas turbines to be a technically feasible alternative. (TSD p.30) However, Ecology rejected CCS as BACT based on its apparent agreement with PSE's technical and cost analysis of CCS. (TSD at p.31.) This conclusion is unsupported because PSE failed to conduct a thorough analysis of the technical potential and cost of CCS.

a) Availability of Saline Formations

PSE claims that deep saline formations are not a viable option in Washington for CCS.[27] Ecology agreed with this conclusion, finding that there was "no available saline formation within a 50 mile radius of the facility." (TSD at p.31.) There is no basis for this conclusion. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) released the fourth edition of the United States Carbon Utilization and Storage Atlas (Atlas IV) in 2012.[28] The West Coast Regional Carbon Sequestration Partnership (WESTCARB) in Atlas IV clearly identified the Northwest, and the Puget basin in particularly, as a prime area of saline storage.

> In Oregon and Washington, western coastal basins containing sandstone and shale sequences up to 10,000 meters (33,000 feet) thick have sites that appear suitable for CO_2 storage. The total CO_2 storage resource for these sedimentary basins is in the range of 40 billion to 590 billion metric tons

[26] http://www.siemens.com/press/en/pressrelease/?press=/en/pressrelease/2010/fossil_power_generation/efp201009120.htm
[27] Application, Appendix H, p.5-10.
[28] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/

> (50 billion to 650 billion tons). The basin with the largest CO_2 storage potential is Washington's Puget Trough.[29]

Skagit Bay and nearby inland sites, which are less than 10 miles from the Fredonia site, are shown on the WESTCARB map as a potential saline storage area. Other suitable locations may be even closer. It is therefore incorrect to assume, without any supporting references or documentation, that saline formations are unavailable to provide for CCS.

b) <u>Cost of CCS</u>

CCS is by far the most effective add-on GHG control technology. PSE's application shows that the CO_2e emissions rate of the LMS-100 turbine with CCS would be 120 lb/MW-hr.[30] This is an order of magnitude lower than the proposed permit's BACT limit of 1,138 lb/MW-hr for the LMS 100 without CCS. Despite its finding that CCS was by far the most effective GHG control technology, Ecology rejected CCS in step four of the top-down process on the basis of PSE's conclusion that the CO_2 avoided using CCS was not cost effective. (TSD at p. 31.) However, PSE's analysis assumed a cost of $76 per ton based on a published November 2010 U.S. Department of Energy cost estimate for combined cycle natural gas plants with CCS systems installed.[31] PSE then compared the $76 per ton national figure with a $20 per ton CO_2e approximate social cost of carbon based on an EPA presentation.[32] This analysis is flawed for multiple reasons.

First, the PSE application concedes that PSE "has not attempted a project-specific or site-specific cost estimate for implementing one of the CCS options discussed above."[33] This generalization of CCS costs, which Ecology accepted without further analysis, is not appropriate. Ecology is required to make site-specific findings as to the cost of pollution control at the Fredonia plant, and not merely the generic costs nationally. (NSR Manual at p.B.35.)

Second, Ecology's exclusion of CCS based on cost is inappropriate because there is no evidence that CCS at Fredonia would be different from the cost of CCS or other BACT options at similar plants. When determining if a pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT based on a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." (NSR Manual at B.44.) This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. Ecology and PSE inappropriately compare the cost of CCS to an arbitrary threshold. To reject CCS, BACT requires a demonstration that the costs of pollutant removal are disproportionately high for the specific facility <u>compared to the cost of control at other facilities</u>. (NSR Manual, p.B.45.) No such CCS comparison was made here. Ecology merely identified some examples of other BACT permits where CCS had been rejected (TSD at p.29-30) rather than comparing the relative cost of CCS between Fredonia and other comparable facilities.

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[29] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/WESTCARB-Atlas-IV-2012.pdf (page 96)
[30] Application, Appendix H, Table 5-4, p.5-13.
[31] Application, Appendix H, p.5-13.
[32] Application, Appendix H, p.5-14.
[33] Application, Appendix H, p.5-13.

Third, even if it was appropriate to compare the incremental cost of CO_2 control to an arbitrary threshold, which it is not, the assumption that $20 per ton of CO_2e avoided is an appropriate threshold is completely unsupported. There are several other sources concluding that carbon has a much higher social cost. A recent study found that social cost of carbon estimates range from $28 up to $893.[34] These thresholds suggest that CCS at $76/ton would be a more economic choice compared to higher estimated social costs of carbon.

In summary, to reject CCS based on cost-effectiveness at step 4, Ecology must determine that the cost of CCS at Fredonia is disproportionate to the cost of the same technology applied to similar sources elsewhere. Failing that, the applicant must at the very least evaluate the costs of CCS at Fredonia against the best estimate of the costs of failing to require the same level of control as would result from the use of CCS. That was not done for the draft permit; instead, Ecology evaluated the national generic cost-per-ton of CCS control on natural gas combined cycle plants, against an arbitrary $20/ton figure, failing to reference the alternative social cost of carbon or the costs of the same or similar levels of CO_2 capture and sequestration elsewhere. Such analysis represents clear error – and it is insufficient to justify rejection CCS as CO_2 BACT for Fredonia.

5. **PM Limits are too High**

The proposed permit's PM BACT limits far exceed comparable limits. Ecology states, "it is impractical to compare the proposed PM emission limits with PM emission limits and performance data from simple cycle combustion turbines in other regions." (TSD at p.20.) This conclusion is based on the assumption of generally higher sulfur content in Canadian natural gas compared to other sources of natural gas such as those in California. (TSD at p.20.) Ecology therefore relies on two BACT PM permitted limits for simple cycle turbines in Washington State. These permit limits are not the appropriate benchmark. Compliance stack tests are often orders of magnitude lower than BACT limits in the RBL Clearinghouse. Since there are numerous permitted gas turbines operating in Washington using Canadian natural gas, there should be a ready source of data to determine whether an increase in PM limits is necessary because of the properties of Canadian natural gas. Ecology should review stack tests of similar uncontrolled natural gas fired units that use Canadian natural gas to determine whether an increase in BACT limits is warranted. Such an evaluation should be made part of the record and be subject to public comment.

6. **The Air Quality Analysis Is Insufficient**

Ecology determined that the plant's CO, PM_{10} and $PM_{2.5}$ impacts would not cause a violation of the NAAQS or the increments solely on the basis of a comparison between the facility's predicted impacts and "significant impact levels" or "SILs." (TSD at 46.) This conclusion is insufficient unless Ecology determines that the impacts, even if below the SIL, are not sufficient when added to background concentrations and impacts from other nearby facilities, to cause or contribute to a violation of the ambient air quality standards or the increments. For example, Ecology's analysis indicates that the 24-hour $PM_{2.5}$ impacts from the proposed new combustion turbine(s) could be 0.48 to 1.149 $\mu g/m^3$. (TSD at 46.) If the background concentration and

[34] Ackerman, *Climate Risks and Carbon Prices: Revising the Social Cost of Carbon*, p. 2 (available at: http://www.sei-international.org/mediamanager/documents/Publications/Climate-mitigation-adaptation/Economics_of_climate_policy/sei-climate-risks-carbon-prices-2011-full.pdf).

impacts from other nearby facilities are near the 35 $\mu g/m^3$ NAAQS (or 2 $\mu g/m^3$ and 9 $\mu g/m^3$ increments), then this amount of pollution could cause a violation of the standards. There is no basis in the regulations or the Clean Air Act for permitting a facility that will cause or contribute to a violation of the NAAQS or an increment simply because its' impact is "below the SIL." Therefore, absent a determination by Ecology (on the record) that the impacts from the facility will not cause or contribute to a violation of the NAAQS or increment notwithstanding the fact that they are below an arbitrary number set as the SIL, there is not a sufficient legal basis on which to issue the permit.

Notably, the only SIL that was ever actually adopted into the PSD regulations—for $PM_{2.5}$—was recently vacated by the D.C. Circuit. *See Sierra Club v. EPA*, Slip Op., Case No. 10-1413 (D.C. Cir. Jan. 22, 2013).Moreover, even if the use of a SIL without an additional determination that the plant's impacts will not cause or contribute to a violation of the NAAQS or increment notwithstanding that they are below the SIL threshold was allowed, the concept of the SIL is based on *de minimis* theory of law. Under that theory, Ecology is still required to demonstrate that the SIL is at a level below which regulating the air pollution impact would be of trivial or no value. Ecology has not made that determination on the record here.

7. <u>No Consideration of Secondary PM2.5 Formation</u>

It appears that the air quality analysis includes only the impacts from primary PM_{10} and $PM_{2.5}$. However, as Ecology is aware, large amounts of the $PM_{2.5}$ in the ambient air are the result of secondary formation from precursors that will also be emitted from the Fredonia plant. Ecology's air quality analysis for particulates must include the impact from both primary and secondary $PM_{2.5}$.

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

/s/ Travis Ritchie

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Appendix B. Sierra Club Fredonia Calculations

Emissions Calculations				
Assumptions: 2880 hour case	2880	2880	2880	2880
Use draft permit emission rates and fuel usage				
Use 2012 GTW cost of equipment and unit capacity figures				
Use PSE assumptions for all other inputs: including				
book life, discount rate FOM & VOM rates, escalation factors				
capital recovery charges, fuel cost and levelizing factor				

use PSE/Ecology factor from net efficiency to emission limit

NORMALIZE ALL RESULTS TO 198.8 MW

	2xLMS 100	7FA.05	SGT6-5000F4	7FA.04
Plant Capacity, net (MW)	198.8	215	208	185
Capacity Factor	0.329	0.329	0.329	0.329
Generation (MW-h)	572,544	619,200	599,040	532,800
Heat rate, net (LHV)	7668	8999	8955	8999
Heat rate, net (HHV)	8511	9989	9940	9989
PSE/Ecology proposed in use factor	1.1	1.1	1.1	1.1
PSE/Ecology proposed in use heat rate (Btu/Kwh)	9743	11122	10942	11216
Fuel CO2 rate (lb/MMBtu HHV)	115.9	115.9	115.9	115.9
Fuel CO2e conversion(lb/MMBtu)	116.8	116.8	116.8	116.8
Plant ISO "new and clean emission rate"	994.1	1166.7	1161.0	1166.7
PSE proposed emission limit (lb/MWh)	1138.0	1299.0	1278.0	1310.0
Annual emissions, per hour of operations assumption	325,778	402,170	382,787	348,984
Proposed annual fuel limitation (MMBtu/yr)	5,179,684	4,886,181	4,793,111	4,288,120
Plant Book life (yrs)	35	35	35	35
PSE Discount rate (percent)	8.1	8.1	8.1	8.1
Annual O&M				
First year fixed O&M rate ($/kW-yr)	$15.71	$11.48	$11.76	$12.32
First year fixed O&M cost	$3,123,148	$2,468,200	$2,446,080	$2,279,200
First year fixed O& M, normalized to 198.8MW	$3,123,148	$2,282,224	$2,337,888	$2,449,216
FOM escalation factor (%/yr)	3	3	3	3
FOM Levelized Cost ($/yr)	$4,046,366	$3,197,812	$3,169,153	$2,952,943
FOM Levelized Cost, normalized to 198.8 MW	$4,046,366	$2,956,861	$3,028,979	$3,173,216
First year variable O&M rate ($/MW-hr)	$3.58	$11.88	$10.28	$10.68
First year variable O&M cost ($)	2,049,708	7,356,096	6,158,131	5,690,304
First year variable O&M cost ($), normalized to 572,544Mwh	$2,049,708	$6,801,823	$5,885,752	$6,114,770
VOM escalation factor (%/yr)	3	3	3	3
VOM Levelized Cost ($/yr)	$2,655,611	$9,530,595	$7,978,506	$7,372,386
VOM levelized cost, normalized to 575,136 MWh/yr	$2,655,611	$8,812,476	$7,625,610	$7,922,326
Fuel				
Fuel ($/MMBtu,HHV)	$8.08	$8.08	$8.08	$8.08
First year fuel ($/yr)	$45,073,330	$55,642,754	$52,960,880	$48,284,088
Normalized to 572,544 MWh/yr	$45,073,330	$51,450,137	$50,618,380	$51,885,820
Fuel escalation rate (%yr)	3	3	3	3
Fuel levelized cost ($/yr)	$58,397,232	$72,091,030	$68,616,381	$62,557,105
Fuel levelized cost, normalized to 199.7 MW	$58,397,232	$66,659,055	$65,581,426	$67,223,527
Capital Cost				
Equipment Cost $/kw	$367.00	$251.00	$251.00	$258.00
Equipment Cost	$72,959,600	$53,965,000	$52,208,000	$47,730,000
Capital recovery factor (%)	8.67	8.67	8.67	8.67
Annual capital cost for equipment	$6,325,597	$4,678,766	$4,526,434	$4,138,191
normalized to 198.8 MW	$6,325,597	$5,060,033	$4,735,906	$3,850,932
Levelized cost	$8,195,476	$6,061,832	$5,864,470	$5,361,461
Levelized cost, normalized to 198.8 MW	$8,195,476	$6,555,804	$6,135,864	$4,989,287
Total Cost				
First year fuel, O&M & CAPEX	$56,571,783	$70,145,815	$66,091,525	$60,391,783
First year fuel, O&M & CAPEX, normalized to 572,544MWh	$56,571,783	$65,594,217	$63,577,926	$64,300,738
Levelized fuel, O&M & CAPEX	$73,294,685	$90,881,269	$85,628,510	$78,243,896
Levelized fuel, O&M & CAPEX, normalized to 198.8MW and 572,544MWh	$73,294,685	$84,984,196	$82,371,879	$83,308,357
Emissions, normalized to 572,544Mwh	325,778	371,867	365,856	375,016
Excess emissions, compared to LMS 100 @ 2880 hours	0	46,089	40,078	49,238

Note: Equipment, fuel and operating costs for the LMS 100 are less than for the other simple cycle options at 2880 operating hours.

Emissions Calculations				
Assumptions 2000 hour case	2000	2000	2000	2000
Use draft permit emission rates and fuel usage				
Use 2012 GTW cost of equipment and unit capacity figures				
Use PSE assumptions for all other inputs: including				
book life, discount rate FOM & VOM rates, escalation factors				
capital recovery charges, fuel cost and levelizing factor				

use PSE/Ecology factor from net efficiency to emission limit

NORMALIZE ALL RESULTS TO 198.8 MW

	2xLMS 100	7FA.05	SGT6-5000F4	7FA.04
Plant Capacity, net (MW)	198.8	215	208	185
Capacity Factor	0.228	0.228	0.228	0.228
Generation (MW-h)	397,600	430,000	416,000	370,000
Heat rate, net (LHV)	7668	8999	8955	8999
Heat rate, net (HHV)	8511	9989	9940	9989
PSE/Ecology proposed in use factor	1.1	1.1	1.1	1.1
PSE/Ecology proposed in use heat rate (Btu/Kwh)	9743	11122	10942	11216
Fuel CO2 rate (lb/MMBtu HHV)	115.9	115.9	115.9	115.9
Fuel CO2e conversion(lb/MMBtu)	116.8	116.8	116.8	116.8
Plant ISO "new and clean emission rate"	994.1	1166.7	1161.0	1166.7
PSE proposed emission limit (lb/MWh)	1138.0	1299.0	1278.0	1310.0
Annual emissions, per hour of operations assumption	226,234	279,285	265,824	242,350
Proposed annual fuel limitation (MMBtu/yr)	5,179,684	4,886,181	4,793,111	4,288,120
Plant Book life (yrs)	35	35	35	35
PSE Discount rate (percent)	8.1	8.1	8.1	8.1
Annual O&M				
First year fixed O&M rate ($/kW-yr)	$15.71	$11.48	$11.76	$12.32
First year fixed O&M cost	$3,123,148	$2,468,200	$2,446,080	$2,279,200
First year fixed O& M, normalized to 198.8MW	$3,123,148	$2,282,224	$2,337,888	$2,449,216
FOM escalation factor (%/yr)	3	3	3	3
FOM Levelized Cost ($/yr)	$4,046,366	$3,197,812	$3,169,153	$2,952,943
FOM Levelized Cost, normalized to 198.8 MW	$4,046,366	$2,956,861	$3,028,979	$3,173,216
First year variable O&M rate ($/MW-hr)	$3.58	$11.88	$10.28	$10.68
First year variable O&M cost ($)	1,423,408	5,108,400	4,276,480	3,951,600
First year variable O&M cost, normalized to 397,600MWh	$1,423,408	$4,723,488	$4,087,328	$4,246,368
VOM escalation factor (%/yr)	3	3	3	3
VOM Levelized Cost ($/yr)	$1,844,175	$6,618,469	$5,540,629	$5,119,713
VOM Levelized Cost, normalized to 397,600 Mh	$1,844,175	$6,119,775	$5,295,563	$5,501,616
Fuel				
Fuel ($/MMBtu,HHV)	$8.08	$8.08	$8.08	$8.08
First year fuel ($/yr)	$31,300,924	$38,640,801	$36,778,389	$33,530,616
Normalized to 397,000 MWh	$31,300,924	$35,729,262	$35,151,653	$36,031,819
Fuel escalation rate (%yr)	3	3	3	3
Fuel levelized cost ($/yr)	$40,553,633	$50,063,215	$47,650,265	$43,442,434
Fuel levelized cost, normalized to 397,600MWh	$40,553,633	$46,291,010	$45,542,657	$46,683,005
Capital Cost				
Equipment Cost $/kw	$367.00	$251.00	$251.00	$258.00
Equipment Cost	$72,959,600	$53,965,000	$52,208,000	$47,730,000
Capital recovery factor (%)	8.67	8.67	8.67	8.67
Annual capital cost for equipment	$6,325,597	$4,678,766	$4,526,434	$4,138,191
normalized to 198.8 MW	$6,325,597	$5,060,033	$4,735,906	$3,850,932
Levelized cost	$8,195,476	$6,061,832	$5,864,470	$5,361,461
Levelized cost, normalized to 198.8 MW	$8,195,476	$6,555,804	$6,135,864	$4,989,287
Total Cost				
First year fuel, O&M & CAPEX	42,173,077	50,896,167	48,027,383	43,899,607
First year fuel, O&M & CAPEX, normalized to 198.8 MW and 397,000Mwh/yr	$42,173,077	$47,795,007	$46,312,775	$46,578,335
Levelized fuel, O&M & CAPEX	$54,639,650	$65,941,328	$62,224,517	$56,876,551
Levelized fuel, O&M& CAPEX, normalized to 198.8 MW and 397,600 MWh/yr	$54,639,650	$61,923,450	$60,003,063	$60,347,124
Emissions, normalized to 397,600 MWh/yr	226,234	258,241	254,066	260,428
Excess emissions, compared to LMS 100 @ 2880 hours	0	32,007	27,832	34,194

Note: Equipment, fuel and operating costs for the LMS 100 are less than for the other simple cycle options at 2880 operating hours.

Emissions Calculations				
Assumptions 1000 hour case	1000	1000	1000	1000
Use draft permit emission rates and fuel usage				
Use 2012 GTW cost of equipment and unit capacity figures				
Use PSE assumptions for all other inputs: including				
book life, discount rate FOM & VOM rates, escalation factors				
capital recovery charges, fuel cost and levelizing factor				

use PSE/Ecology factor from net efficiency to emission limit

NORMALIZE ALL RESULTS TO 198.8 MW

	2xLMS 100	7FA.05	SGT6-5000F4	7FA.04
Plant Capacity, net (MW)	198.8	215	208	185
Capacity Factor	0.114	0.114	0.114	0.114
Generation (MW-h)	198,800	215,000	208,000	185,000
Heat rate, net (LHV)	7668	8999	8955	8999
Heat rate, net (HHV)	8511	9989	9940	9989
PSE/Ecology proposed in use factor	1.1	1.1	1.1	1.1
PSE/Ecology proposed in use heat rate (Btu/Kwh)	9743	11122	10942	11216
Fuel CO2 rate (lb/MMBtu HHV)	115.9	115.9	115.9	115.9
Fuel CO2e conversion(lb/MMBtu)	116.8	116.8	116.8	116.8
Plant ISO "new and clean emission rate"	994.1	1166.7	1161.0	1166.7
PSE proposed emission limit (lb/MWh)	1138.0	1299.0	1278.0	1310.0
Annual emissions, per hour of operations assumption	113,117	139,643	132,912	121,175
Proposed annual fuel limitation (MMBtu/yr)	5,179,684	4,886,181	4,793,111	4,288,120
Plant Book life (yrs)	35	35	35	35
PSE Discount rate (percent)	8.1	8.1	8.1	8.1
Annual O&M				
First year fixed O&M rate ($/kW-yr)	$15.71	$11.48	$11.76	$12.32
First year fixed O&M cost	$3,123,148	$2,468,200	$2,446,080	$2,279,200
First year fixed O& M, normalized to 198.8MW	$3,123,148	$2,282,224	$2,337,888	$2,449,216
FOM escalation factor (%/yr)	3	3	3	3
FOM Levelized Cost ($/yr)	$4,046,366	$3,197,812	$3,169,153	$2,952,943
FOM Levelized Cost, normalized to 198.8 MW	$4,046,366	$2,956,861	$3,028,979	$3,173,216
First year variable O&M rate ($/MW-hr)	$3.58	$11.88	$10.28	$10.68
First year variable O&M cost ($)	711,704	2,554,200	2,138,240	1,975,800
First year variable cost, normalized to 198,800 MWh	$711,704	$2,361,744	$2,043,664	$2,123,184
VOM escalation factor (%/yr)	3	3	3	3
VOM Levelized Cost ($/yr)	$922,087	$3,309,234	$2,770,314	$2,559,856
VOM Levelized Cost, normalized to 198,800 MWh/yr	$922,087	$3,059,887	$2,647,781	$2,750,808
Fuel				
Fuel ($/MMBtu,HHV)	$8.08	$8.08	$8.08	$8.08
First year fuel ($/yr)	$15,650,462	$19,320,401	$18,389,195	$16,765,308
Normalized to 198,800 MWh/yr	$15,650,462	$17,864,631	$17,575,826	$18,015,910
Fuel escalation rate (%yr)	3	3	3	3
Fuel levelized cost ($/yr)	$20,276,817	$25,031,608	$23,825,132	$21,721,217
Fuel levelized cost, normalized to 198,800 MWh/yr	$20,276,817	$23,145,505	$22,771,328	$23,341,503
Capital Cost				
Equipment Cost $/kw	$367.00	$251.00	$251.00	$258.00
Equipment Cost	$72,959,600	$53,965,000	$52,208,000	$47,730,000
Capital recovery factor (%)	8.67	8.67	8.67	8.67
Annual capital cost for equipment	$6,325,597	$4,678,766	$4,526,434	$4,138,191
normalized to 198.8 MW	$6,325,597	$5,060,033	$4,735,906	$3,850,932
Levelized cost	$8,195,476	$6,061,832	$5,864,470	$5,361,461
Levelized cost, normalized to 198.8 MW	$8,195,476	$6,555,804	$6,135,864	$4,989,287
Total Cost				
First year fuel, O&M & CAPEX	25,810,911	29,021,566	27,499,948	25,158,499
First year fuel, O&M & CAPEX, normalized to 198.8MW and 198,800 MWh	$25,810,911	$27,568,632	$26,693,285	$26,439,242
Levelized fuel, O&M & CAPEX	$33,440,746	$37,600,486	$35,629,070	$32,595,477
Levelized fuel, O&M ,& CAPEX, normalized to 198.8MW and 198,800 MWh	$33,440,746	$35,718,058	$34,583,953	$34,254,814
Emisions, normalized to 198,800 MWh/yr	113,117	129,121	127,033	130,214
Excess emissions compared to LMS 100 at 1,000 hours	0	16,004	13,916	17,097

Note: Equipment, fuel and operating costs for the LMS 100 are less than for the other simple cycle options at 2880 operating hours.

Appendix C. York Plan Holding Review Memo

Commonwealth of Pennsylvania
Department of Environmental Protection
Air Quality Program
September 6, 2011

Subject: York Plant Holding, LLC
Springettsbury Township, York County
Plan Approval No. 67-05009C

To: William R. Weaver WRW 9/7/11
Regional Manager, Air Quality

Thru: Daniel C. Husted, PE DCH 9/7/11
Environmental Engineering Manager
West Permitting Section

From: Harold Wynkoop HW
West Permitting Section

Project Description

A Plan Approval Application was received on June 9, 2010 for the existing York Plant Holding, LLC facility located in Springettsbury Township, York County. The company operates a turbine based electrical generation facility at this location and is proposing to expand the (electrical) capacity of the facility through the construction of two new simple cycle turbines.

The existing facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input, which is one of the 28 source categories listed in 40 CFR Section 52.21(b)(1)(i)(a). Existing sources at the facility include four natural gas fired Solar Mars 90 gas turbines, in combined cycle with each having a heat input capacity of 98.6 mmBtu/hr and a capacity of 8.3 MW. Each turbine is equipped with a heat recovery steam generator with duct burners rated at 19.8 mmBtu/hr. The steam feeds two steam turbines each rated at 9.5 MW.

The facility is located in an area that is attainment for all NAAQS pollutants except for PM2.5; however, since the facility is located in the Northeast Ozone Transport Region, it is considered non-attainment for ozone as well.

Table 1.1 - Existing facility (before construction of two new turbines)

Pollutant	PTE (TPY)
NOx	280.3
CO	203.2
VOC	3.5
PM10	11.1
PM2.5	11.1
SO2	5.7
HAPS	1.6

Sources / Control

This application proposes to add two simple cycle, aero-derivative, dual fuel (natural gas and ultra-low sulfur distillate) combustion turbines. The company submitted this application with consideration for three different turbine model options and will select one of the three model options depending on business factors at the time of purchase. The addition of these two turbines would increase the gross electrical output by between 82.6 and 123 MW, depending on the turbine vendor that is selected. The current electrical generation capacity of the facility is 52.2 MW.

The expansion will involve the installation of the following equipment:

(a) Two (2) turbines from the following three options:

a. Rolls Royce Trent 60 (approximately 61.5 MW each)
b. Pratt & Whitney FT8 (49 MW, each)
c. GE LM6000 (approximately 47 MW, each)

(b) In addition to operational limitations, air emissions will be minimized by the following add-on control equipment:

a. Water injection followed by Selective Catalytic Reduction System (SCR) utilizing aqueous ammonia for NOx control;
b. Catalytic oxidizer for CO control

(c) One (1) 300,000 gallon fixed roof distillate oil storage tank
(d) One (1) 15,000 gallon tank to hold a 19 % solution of aqueous ammonia for the SCR system
(e) One (1) 200,000 gallon demineralized water storage tank

The turbines will employ water injection with SCR and a Catalytic Oxidizer to control emissions. Inlet fogging will be utilized in order to improve the power output and turbine heat rate during periods of higher ambient temperatures.

Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NNSR)

PSD

The facility is one of the 28 source categories listed in 40 CFR 5.21(b)(1)(i)(a) and is considered a major stationary source subject to the PSD requirements of 40 CFR 52.21 since it is located in an attainment area and has the potential-to-emit of regulated air pollutants, NOx and CO in amounts greater than 100 tons per year. The Step 1 PSD applicability analysis for the regulated PSD pollutants for this project is shown in Table 1.2. The project was found to be significant for PM, PM_{10} and Greenhouse Gases (GHGs) in Step 1. Since there have been no creditable emission increases or decreases realized at the facility in the past 5 years, the project PTE values in Table 1.2 are also net emission increases per Step 2 of the applicability analysis. The project is significant for PM, PM_{10} and GHGs.

Air Quality Modeling

In accordance with 40 CFR 52.21(k)- source impact analysis, the company was required to show that the emission increases from the project would not cause or contribute to air pollution in violation of National Ambient Air Quality Standards (NAAQS) in any air quality control region or any applicable maximum allowable increase over the baseline concentration in any area. (PSD increment standards).

Air Quality Modeling (continued)

In accordance with 40 CFR 52.21(o) - additional impact analyses, the company is required to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the project and general commercial, residential, industrial and other growth associated with the project. The company is also required to provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the project.

Additionally, in accordance with 40 CFR 52.21(p) - Sources impacting Federal Class I areas—additional requirements - the company was required to show that the emissions from the plant would not have an adverse impact on the air quality-related values (including visibility) of any Federal Class I areas.

Source Impact Analysis

The facility is located in the South Central Pennsylvania Interstate Air Quality Control Region, which is a Class II PSD area. The modeling analysis provided with the application demonstrated that, with restrictions on the time of day oil and gas can each be combusted, the maximum concentration of PM-10 due to the project was estimated to be less than the corresponding 24-hour Class II significant impact levels (SIL); therefore, a NAAQS and PSD increment analysis for PM-10 is not needed. Conditions are included in the plan approval that restrict oil and gas burning hours as provided in the analysis.

Additional impact analyses

As a result of the analysis, no impairment to visibility or significant impacts to soils and vegetation were found and no impacts to the air quality due to industrial, commercial and residential growth are anticipated.

Federal Class I Area Analysis

The nearest Federal Class I areas with approximate distances from the facility are as follows:

- Shenandoah National Park, Virginia - 178 kilometers
- Brigantine Wilderness Area, New Jersey - 197 kilometers
- Dolly Sods Wilderness Area, West Virginia - 250 kilometers
- Otter Creek Wilderness Area, West Virginia - 270 kilometers
- James River Face Wilderness Area, Virginia - 355 kilometers

In accordance with the Initial Screening Criteria contained in section 3.2 of the "Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised (2010)", a source that is located greater than 50km from a Class I area is considered to have negligible impacts on air quality-related values and further Class I AQRV impact analyses would not be requested by the respective Federal Land Managers (FLMs) if its Q/D factor is less than 10. The Q/D factor is determined where Q is the total SO2, NOx, PM10 and H2SO4 annual emissions, based on 24-hour maximum allowable emission, in tons per year and D is the distance from the Class I area, in kilometers.

The maximum Q/D ratio, which corresponds to the closest Class 1 Area, Shenandoah National Park, is 246.3 tpy/177 km or 1.4; therefore, a Class 1 Area impact analysis in accordance with 40 CFR 52.21(p) is not needed.

Air Quality Modeling (continued)

Federal Class I Area Analysis (continued)

Additionally, letters and / or Request for Determination of Need for a Class I AQRV Modeling Analysis were sent to the FLMs for the Shenandoah National Park, Brigantine Wilderness Area, Dolly Sods Wilderness Area, Otter Creek Wilderness Area and James River Face Wilderness that provided notification of the project as well as project emissions and distances from the Class 1 Areas.

In response to notification letters sent to Ms. Jill Webster, Environmental Scientist for the US Fish and Wildlife Service and Ms. Andrea Stacy, National Park Service, it was determined that based on the emissions of the project and the distance from the Class 1 Area (Q/D), the need for a Class I AQRV analysis is not necessary for the Brigantine Wilderness Area and Shenandoah National Park, respectively.

Non-attainment New Source Review (NNSR)

The facility is located in an area that is non-attainment for ozone and $PM_{2.5}$, and is subject to NNSR requirements for these pollutants. Since VOCs and NOx are considered precursors for ozone, the facility is also required to address these as non-attainment pollutants. Similarly, sulfur dioxide and NO_x are considered precursors to $PM_{2.5}$ and must be included in the analysis. The facility shut down two turbines in late 2004 and banked 7.35 tons per year of NOx ERCs.

A Step 1 NNSR applicability analysis revealed that none of the project emission increases of the subject pollutants (VOC, NO_x, $PM_{2.5}$ or SO_2) are significant. The existing facility is major for NO_x and a Step 2 NNSR analysis was conducted. Since there have been no creditable emission increases for NOx in the past 10 years, the de minimis emissions increase associated with this project are also not significant; thus, this project does not trigger NNSR.

York Plant Holding, Inc.
Plan Approval 67-05009C

September 6, 2011

Table 1.2 – Project PTE and NSR Applicability

Pollutant	Significant Emission Rate Threshold (tpy)	Project PTE (TPY) [Turbine Source ID's 047 & 048]	Subject to NNSR/PSD Permitting?
Nonattainment New Source Review (NNSR)			
Ozone – NOx (precursor to ozone)	40	21.7	No
Ozone – VOC (precursor to ozone)	50[b]	6.4	No
$PM_{2.5}$[a]	100[c]	25.4	No
$PM_{2.5}$ Precursor - NOx	40	21.7	No
$PM_{2.5}$ Precursor – SO_2	100[d]	6.5	No
Prevention of Significant Deterioration (PSD)			
CO	100	20.7	No
NOx	40	21.7	No
SOx	40	6.5	No
PM[a]	25	25.4	*Yes*
PM_{10}[a]	15	25.4	*Yes*
VOCs	40	6.4	No
GHGs[f] (CO2e)	75,000	155,926	*Yes*
Lead (Pb)	0.6	0.01	No
Fluorides	3	0.15	No
Sulfuric Acid Mist (H_2SO_4)	7	1.4	No

[a]All particulate emissions are assumed to be $PM=PM_{10}=PM_{2.5}$.
[b]Since the facility is currently minor for VOC, an increase of less than 50 tpy is de minimis under NNSR.
[c]Since the facility is currently minor for $PM_{2.5}$, an increase of less than 100 tpy is de minimis under NNSR.
[d]Since the facility is currently minor for SO_x, an increase of less than 100 tpy is de minimis under NNSR.
[f]PSD applies to GHGs if net GHG emissions are equal to or greater than 75,000 tpy on a CO2e basis.

Applicable Requirements

Emissions increases (Refer to Table 1.2) associated with the expansion are subject to the following Federal and State requirements, specifically:

1) Best Available Control Technology (BACT) for:

    a. PM/PM10
    b. Greenhouse Gases (GHGs)

2) Acid Rain
3) New Source Performance Standards (NSPS), Subpart KKKK - Combustion Turbines
4) CAM
5) Cross State Transport Rule

6) State requirements of Best Available Technology (BAT) for:

    a. NOx
    b. SO_2
    c. CO
    d. VOCs
    e. PM2.5
    f. Ammonia

BACT

EPA recommends that its five-step "top-down" BACT process to determine BACT should be used. The five steps are as follows:

Step 1: Identify all available control technologies for a given pollutant and ranked in descending order of control effectiveness.

Step 2: Eliminate technically infeasible options.

Step 3: Rank the remaining options from most to the least in control effectiveness.

Step 4: Evaluate and document the energy, environmental and economic impacts of the top ranked option.

- If these considerations do not justify eliminating the top-ranked option, it should be selected as BACT at the fifth and last step.

- If the energy, environmental, or economic impacts of the top-ranked option demonstrate that this option is not achievable, the evaluation continues in this step with an examination of the abovementioned impacts of the second ranked option.

- This assessment should continue in this step until an achievable option is identified and finally selected as BACT.

Step 5: Select BACT

- It is important to remember that BACT should include an emission limitation that is achievable by the selected control strategy.

PM/PM_{10} – BACT

Using a top-down approach for determining BACT for particulate control, we have the following:

1. Available Control Technologies

Particulate matter control techniques can be either pre-combustion, combustion control or post-combustion. Using clean fuel is a pre-combustion control option consideration for controlling particulate matter emissions while using fabric filter and electrostatic precipitators are post combustion control options to consider. Good combustion practices can be used to supplement both, pre or post combustion controls.

Pre-combustion and combustion controls

Fewer particulates, including those associated with sulfur in the fuel, are emitted with the combustion of clean burning fuels such as natural gas and ultra-low sulfur distillate. The filtering of air entering the turbine intake also helps limit particulate emissions. Additionally, employing good combustion practices will help minimize condensable particulate matter emissions and will also lead to better efficiencies, which in turn, will lead to a reduction in fuel consumption and regulated pollutant emissions.

Post-combustion controls

Electrostatic precipitators and fabric filters were each considered for the control of particulate matter emissions for this project.

2. Eliminate technically infeasible options

Since post combustion controls such as fabric filters and electrostatic precipitators are not a "demonstrated" control technology for a combustion turbine, the "availability" and "applicability" of the controls should be considered

Even though fabric filters and electrostatic precipitators are considered "available" control technologies, they are only considered "applicable" if it can reasonably be installed and operated on the source under review; however, a control technology would not be considered applicable if it can be shown that there are physical, chemical, or engineering difficulties that would prevent the successful use of the control option on the emissions unit under review. In this case, extremely high air flows (760,000 ACFM per turbine) and high temperatures (800 deg F) of the turbine exhaust gas would result in excessive fabric filter pressure drops and ESP particle kinetic energy, which would make particulate collection from either of these two control options technically infeasible and therefore, not applicable.

3. Rank remaining control technologies

Uncontrolled particulate emissions from the turbines are expected to be approximately 0.002 gr/dscf for natural gas and 0.007 gr/dscf for ULSD: The remaining control option for particulate is using clean fuels and combustion controls as follows:

1. Clean Fuels and Combustion Control including:
    a. Combusting only Natural Gas or ULSD fuels
    b. Filtering of Combustion Air
    c. Efficient Combustion

PM/PM_{10} – BACT(Continued)

4. Evaluate most effective controls and document results

Since the applicant proposes to implement a control strategy of efficient combustion and using clean fuels, no additional evaluation for energy, environmental or economic impacts are required.

5. Select BACT

The applicant proposes the following as PM/PM_{10} BACT:

1. Efficient combustion
2. The pre-filtration of combustion air
3. Combust only natural gas and ULSD clean burning fuels
4. Particulate emission limits:
    a. 5.9 pounds per hour while combusting natural gas
    b. 15.0 pounds per hour while combusting ULSD

A search of the RACT/BACT/LAER clearing house (RBLC) was conducted by the applicant and the following table summarizes BACT determinations of the 4 most recent projects from the RBLC that apply to large (>25MW) simple cycle turbines. The above PM/PM_{10} determination made by the applicant is consistent with the results of the search.

Additionally, as indicated in Table 2 below, only dry low NOx combustion and good combustion practices has been specified as BACT for recent simple cycle turbine projects. The York Plant Holding proposal is to use SCR and catalytic oxidation for control of NOx, CO, and VOCs.

Table 2 – Recent BACT Determinations

Project	Dahlberg	Dayton	Bosque	Shady Hills	York Plant Holding
Permit Date	5/14/2010	12/3/2009	2/27/2009	1/12/2009	TBD
Turbine Capacity, each	190 MW Simple Cycle Turbine / each	80 MW Simple Cycle	170 MW Simple Cycle Mode	170 MW Simple Cycle Mode	61.5 MW max
CO control	GCP	GCP	GCP	-	GCP/Cat Ox
CO limit NG	9 ppm	20 ppm	9 ppm	6.5 ppm	5 PPM
CO limit oil	30 ppm	42 ppm	-	13.5 ppm	5 PPM
VOC control	GCP	GCP	GCP	-	GCP/CatOx
VOC limit NG	5 ppm	4 lb/hr	4 ppm	-	2.7 ppm
VOC Limit Oil	5 ppm	5.5 lb/hr	-	-	2.0 ppm

Table 2 – Recent BACT Determinations (continued)

Project	Dahlberg	Dayton	Bosque	Shady Hills	York Plant Holding
NOx control NG	DLN	DLN	DLN	DLN	Water/SCR
NOx control oil	Water	Water	-	-	Water/SCR
NOx limit NG	9 ppm	15 ppm	9 ppm	9 ppm	2.5 ppm
NOx limit oil	42 ppm	42 ppm	-	-	5 ppm
PM10 Limit NG	9.1 lb/hr	0.013 lb/mmBtu actual heat input	0.01 lb/mmBtu	-	5.9 lb/hr
PM10 Limit Oil	69.0 lb/hr	0.0260 lb/mmBtu actual heat input	-	-	15 lb/hr
PM control NG	GCP/Pipeline gas	Clean fuels	GCP/Pipeline gas	GCP	GCP/Pipeline gas
PM control oil	ULSD	Clean fuels	-	GCP / ULSD	ULSD
SO2 Limit NG	-	0.0026 lb/mmBtu actual heat input	-	2 gr S/100 Scf of NG	1.6 lb/hr
SO2 Limit Oil	-	0.055 lb S / mmBtu actual heat input	-	0.0015% S by Weight	1.9 lb/hr
SO2 Control NG	-	-	-	2 gr S/100 Scf of NG	Pipeline NG
SO2 Control Oil	-	Low sulfur fuel oil (0.05% S max by weight)	-	ULSD	ULSD

Fugitive PM_{10} – BACT

Since the facility belongs to one of the 28 source categories listed in paragraph 52.21(b)(1)(iii), fugitive emissions should be included in a BACT analysis as per 52.21(b)(20)(vii). Fugitive PM_{10} emissions associated with this project are from roadways due to fuel delivery. Using AP-42 emission factors, fugitive PM_{10} are estimated to be approximately 3.7 pounds per year. The roadways at the facility used by fuel delivery trucks will be paved and the fugitive emissions are based on an average empty and loaded vehicle weight of 23.4 tons and 108.5 of total miles traveled within the facility per year. The BACT determination for fugitive PM10 is determined to be compliance with the fugitive emissions requirements of 25 Pa Code, 123.1 and 123.2.

GREENHOUSE GASES – BACT

Greenhouse Gas PSD applicability

For PSD purposes, GHGs are considered a single air pollutant defined as the aggregate group of the following six individual gases:

- carbon dioxide (CO2)
- nitrous oxide (N2O)
- methane (CH4)
- hydrofluorocarbons (HFCs)
- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF6)

The regulated GHG pollutants emitted by the combustion turbines are CO2, CH4 and N2O.

Generally, a two-step process is used when determining PSD applicability for GHGs. First, the sum total of CO2e emissions, in TPY, of the above six GHGs is used to determine if the source's emissions are a regulated NSR pollutant and second, if the emissions are a regulated pollutant, the sum of the mass emissions, in TPY, of the six GHGs are used to determine if there is a major source or major modification of GHG emissions.

For existing sources making a physical or operational change on or after July 1, 2011, GHGs are considered a regulated NSR pollutant and subject to PSD regulation under Tailoring Rule Step 2. Since the project was subject to PSD regulation under Tailoring Rule Step 1 it is covered under Tailoring Rule Step 2.

Under the Tailoring Rule Step 1, PSD applies to the GHG emissions from a proposed modification if the modification, without considering its emissions of GHGs, would be considered a PSD major modification anyway and the GHG emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 tons per year on a CO2e basis. There are no emission increases or decreases contemporaneous with this project so the net emissions increase is equal to the emissions increase from the project.

CO2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). Global warming potential values are specified in 40 CFR Part 98, Subpart A, Table A-1. Per Table A-1, CO2 has a GWP factor of 1 and the CO2e emissions and net emissions are greater than 75,000 tons per year based on CO2 emissions alone.

This application is subject to PSD for GHG emissions because the modification is already subject to PSD for PM10 emission increases and CO2e GHGs emissions from the modification are greater than 75,000 tons per year.

GREENHOUSE GASES – BACT (continued)

The CO2e emission calculations show below in Table 3 are based on 2150 hours of operation while firing natural gas and 850 hours while firing distillate oil for each turbine.

Table 3 - GHG emission calculations

GE LM6000 Maximum Emissions (Worst Case Operational Limits)

Turbine Heat Input	Natural Gas		Oil
MMBtu/hr (2 units) HHV	832		730
MMBtu/hr (per unit) HHV	416		365
Part 98 Emission Factors (kg/MMBTU)			
	CO_2	CH_4	N_2O
NG	53.02	1.00E-03	1.00E-04
#2 Oil	73.96	3.00E-03	6.00E-04
Kerosene	75.20	3.00E-03	6.00E-04
Mg/year	141,504	3.7	0.6
TPY	155,654	4.0	0.6
GWP	1	21	310
TPY CO_2e	155,654	84	188
Total CO_2e (TPY)	155,926		

Greenhouse Gas BACT Analysis

The primary purpose of the York Plant Holding project is to provide for additional short-term power as needed during those periods of time when other power resources are unable to meet the demand. Internal combustion (IC) engines or simple cycle combustion turbines can meet these demand needs more quickly than a natural gas combined cycle plant could; however, since IC engines operate with less efficiency and higher overall emissions than simple cycle combustion turbines they are not included in this BACT analysis. EPA's document, PSD and Title-V Permitting Guidance For Greenhouse Gases, dated November, 2010 was used as a reference to assist with the BACT review.

1. Available CO2 Control Options

Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) systems capture and provide storage for GHGs. Three processes used for capturing carbon include removing carbon from the fuel prior to combustion; collecting CO2 after combustion; and lastly, using oxygen to combust the fuel rather than air, which increases the concentration of CO2 in the exhaust and reduces the cost of collection. Once the CO2 is captured, it must be sequestered to prevent re-release into the air. Two methods for sequestration include injecting the CO2 deep into the earth or ocean. Another technique recycles captured CO2 by injecting the gas into algae-rich ponds, which would absorb the CO2.

GREENHOUSE GASES – BACT (continued)

Efficiency Improvements

Efficiency considerations are explored as part of this BACT determination. Energy efficiency is considered an important component of this BACT analysis since a reduction in the products of combustion helps minimize GHG's and other regulated NSR pollutants emitted into the atmosphere.

It is recognized that an energy efficiency improvement option that should be considered in this case is the inclusion of combined cycle plants in lieu of simple cycle plants due to the increased efficiencies of combined cycle plants. However, a control strategy can be excluded from consideration in a top-down, case-by-case analysis if it can be shown that the strategy "would disrupt the applicant's basic or fundamental business purpose for the proposed facility".

In this case, YPH proposes to use efficient simple turbines because of the need to quickly meet short-term power demands. Natural gas combined cycle (NGCC) plants are not able to meet this quick demand requirement. Since a NGCC plant would not provide the flexibility that is needed to meet short term power demand and would disrupt the fundamental business purpose of the project, the applicant seeks to eliminate a NGCC unit from consideration for this project.

2. Technically Infeasible Options

Even though CCS is generally considered an available control technology, significant logistical hurdles exist for the transportation and storage or recycling of any captured GHGs. Sequestration sites near the facility have not been established and the acquisition of land or right-of-ways needed for the development of a site or transportation infrastructure would be not be considered reasonable for this project. It is for the abovementioned reasons that CSS is rejected as a technically feasible BACT option for this project.

Recycling captured CO2 in algae ponds is considered technically infeasible at this time because of turbine backpressure compatibility concerns.

3. Ranking of Technically Feasible CO2 Control Options

The only technically feasible BACT option remaining is for the installation of the most efficient simple cycle turbine in terms of the amount of gas combusted per unit of electrical output. The BACT determination for The Russell City Energy Center (RCEC) project, located in Hayward, CA was referenced by the applicant as a basis for the consideration of the GE LM6000 as an efficient simple cycle turbine for the generation of peak power.

For this analysis, instead of providing performance data from a specification sheet, YPH provided data for a GE LM6000 turbine based on actual testing at a location with a similar elevation as the YPH site. Based on 100% load at 92 degrees, the LHV heat rate established through performance testing was determined to be 8,917 BTU/kWh while firing natural gas. In terms of a high heating value (HHV), this corresponds to a heat rate of approximately 9870 BTU/kWh.

Allowances for what is actually achievable in practice, due to parasitic loads on the turbines such as auxiliary equipment and transformer / plant loads, as well as design variables and turbine and aux equipment degradation, were factored in determining the proposed BACT heat rate.

The derivation of the turbine BACT heat rate, adjusted for parasitic loads and design variables and equipment degradation is shown in the following table. The BACT heat rate established below is based on worst-case short-term site conditions.

York Plant Holding, Inc.
Plan Approval 67-05009C

September 6, 2011

GREENHOUSE GASES – BACT (continued)

GE LM6000 Heat Rate – (Aux power Requirements and Parasitic Loads; Turbine & Equipment Degradation)

Gross Turbine Output (92° F and 100% capacity)	39,788 kW
Maximum heat input (92° F and 100% capacity)	392.7 MMBTU/hr (HHV)
Gross Heat Rate (BTU/kWh)	9,870
Parasitic Loads	
Aux Load	480 kW
Transformer loss / Balance of Plant Load	986 kW
Net Turbine Output (92° F and 100% capacity)	38,322 kW
Net Heat Rate (BTU/kWh)	10,247
Allowances	
3.3% for Design Variations	10,585
6% for Turbine Degradation	11,220
1.5% for Auxiliary Equipment Degradation	11,389
BACT Heat Rate (BTU/kWh) (HHV)	**11,389**

4. Evaluate most effective controls and document results

Since the applicant proposes to implement a control strategy of efficient combustion and using clean fuels, no additional evaluation for energy, environmental or economic impacts are required.

5. Select BACT

CO_2e BACT Limits

Even though the applicant wants to retain the ability to purchase any of the three turbines for purposes of maintaining a business advantage, in terms of heat rate, the GE LM6000 is the most efficient turbine and the GHG emission rates are developed based on the efficiency of that turbine. Potential greenhouse gases will be further reduced with a combined 6000-hour total / 1700-hour oil firing 12-month operational limit imposed on the new turbines.

Natural Gas

Using the 11,389 Btu/kWh BACT heat rate derived above and the CO2, CH4 emission factors and GWPs shown in Table 3 for natural gas, the BACT CO2e permit limit for each turbine while combusting natural gas is 1,330 lb/MWh. (Based on a net power output and a 30-day rolling average)

ULSD

Using the 11,389 Btu/kWh BACT heat rate derived above and the CO2, CH4 and N20 emission factors and GWPs shown in Table 3 for kerosene, the BACT CO2e permit limit for each turbine while combusting oil is 1,890 lb/MWh. (Based on a net power output and a 30-day rolling average)

BAT Determinations

Recent BACT and LAER determinations for simple cycle turbines were used as a benchmark when establishing BAT for this project. The follow are discussions and recommendations for each BAT determination for NOx, CO, VOC, SO2 and ammonia. Start-up and Shut-down emissions are excluded from BAT determinations since emissions are protected by 12-month rolling limits. Start-up periods are defined as a 60-minute period commencing with initial fire. Shut-down periods are defined as a 60-minute period that ends with complete cessation of firing. A summary of BACT & BAT determinations are presented in Table 4.

Nitrogen Oxides (NOx) – BAT

As shown in Table 2, recent BACT determinations for simple cycle turbines specify dry low NOx burners and water injection for NOx control. YPH is proposing to control NOx emissions by using SCR, which typically is required for units subject to LAER. Each turbine manufacturer guarantees that NOx emissions will be below 2.5 PPM while combusting NG and 5.0 PPM while combusting oil; therefore, YPH is proposing NOx BAT to be 2.5 PPM while firing natural gas and 5.0 PPM while firing ultra-low sulfur distillate. The plan approval will limit the combined 12-month rolling NOx emissions from the two turbines to 21.7 tons. NOx emissions will be monitored and recorded using CEM. Short-term NOx emission limits do not apply during start up and shut down but are included in the 12-month limit.

Carbon Monoxide (CO) – BAT

As shown in Table 2, recent BACT determinations for simple cycle turbines specify good combustion practices without add-on controls for CO control. Those determinations for simple cycle turbines have CO limits ranging from 6.5 ppm to 20 ppm while combusting natural gas and from 13.5 ppm to 42 ppm while combusting distillate oil. York Plant Holding is proposing to install catalytic oxidization for CO control and proposes permit limits of 5 ppm while combusting both natural gas and distillate oil as BAT. The plan approval will limit the combined 12-month rolling CO emissions from the two turbines to 20.7 tons. CO emissions will be monitored and recorded using CEM. Short-term CO emission limits do not apply during start up and shut down but are included in the 12-month limit.

Volatile Organic Compound (VOC) – BAT

As shown in Table 2, recent BACT determinations for simple cycle turbines specify good combustion practices without add-on controls. Those determinations for simple cycle turbines have VOC limits in the 4 -5 ppm range while combusting natural gas and oil. York Plant Holding is proposing to install catalytic oxidization and limit VOC emissions to 2.7 ppm while combusting natural gas and 2.0 ppm while combusting distillate oil as BAT. The plan approval will limit the combined 12-month rolling VOC emissions from the two turbines to 6.4 tons.

Sulfur Dioxide (SO2) – BAT

Recent SO_2 BACT determinations limit fuel sulfur content. Dayton has the fuel sulfur content limited to 0.05% by weight. The Shady Hills permit requires ultra-low sulfur diesel (ULSD) – 15 ppm sulfur content (0.0015% S by weight). York Plant Holdings proposes to fire only ultra-low sulfur kerosene (15 ppm max sulfur), ultra-low sulfur diesel (15 ppm max sulfur) or pipeline natural gas (0.5 grains or less of total sulfur per 100 standard cubic feet) as BAT. The plan approval will limit the combined 12-month rolling SO_x emissions (as SO_2) from the two turbines to 6.5 tons.

BAT Determinations (continued)

Ammonia – BAT

Since most turbine installations have not required SCR as BACT or BAT, a review of recent turbine permits subject to LAER revealed that 5 ppm ammonia slip is a typical limit. York Plant Holding proposes to use a 5-ppm limit for ammonia slip in conjunction with aggressive NOx limits as proposed in this application. Ammonia emissions will be monitored and recorded using a continuous monitoring system.

Table 4 - Summary of BACT & BAT Determinations for construction of two new turbines at YPH:

Pollutant	Fuel	Proposed Control	Proposed Emission Limit	Averaging Time	BAT -or- BACT
NOx	Natural Gas	WI/SCR	2.5 PPM	1-hour	BAT
NOx	Ultra-Low Sulfur Distillate	WI/SCR	5.0 PPM	1-hour	BAT
CO	Natural Gas	GCP/CatOx	5.0 PPM	3-hour rolling	BAT
CO	Ultra-Low Sulfur Distillate	GCP/CatOx	5.0 PPM	3-hour rolling	BAT
PM/PM10/PM2.5	Natural Gas	Pipeline NG Fuel Only	5.9 lb / hr	1-hour	BACT
PM/PM10/PM2.5	Ultra-Low Sulfur Distillate	ULSD Fuel Only	15 lb / hr	1-hour	BACT
VOC	Natural Gas	GCP/CatOx	2.7 PPM	1-hour	BAT
VOC	Ultra Low Sulfur Distillate	GCP/CatOx	2.0 PPM	1-hour	BAT
SO2	Natural Gas	Pipeline NG Fuel Only	1.6 lb / hr	1-hour	BAT
SO2	Ultra Low Sulfur Distillate	ULSD Fuel Only	1.9 lb / hr	1-hour	BAT
NH3	Natural Gas	N/A	5.0 PPM	3-hour rolling	BAT
NH3	Ultra Low Sulfur Distillate	N/A	5.0 PPM	3-hour rolling	BAT
GHGs (CO_2e)	Natural Gas	N/A	1,330 lb/MWh	30-day	BACT
GHGs (CO_2e)	Ultra Low Sulfur Distillate	N/A	1,890 lb/MWh	30-day	BACT

Acid Rain

The facility is currently exempt from EPA's Title IV Acid Rain program since the current nameplate capacity for each turbine generator is less than 25 MWe; however, the new turbines proposed for this project are greater than 25 MWe and this expansion project is subject to EPA's Title IV Acid Rain requirements. The company submitted an acid rain permit application and compliance plan to the Department on Oct 17, 2010.

As provided in 25 Pa. Code, Section 127.531(c), the permit application and the compliance plan, including amendments thereto, shall be binding on the owner or operator or the designated representative of the owner or operator and shall be enforceable as a permit for purposes of this section until a permit is issued by the Department. The Acid Rain requirements will be added to the operating permit during the next permit renewal.

40 CFR Part 60, Subpart KKKK

The turbines are subject to the requirement of 40 CFR Part 60, Subpart KKKK. The NOx emission limits specified in the subpart for each turbine while firing natural gas are 25 ppm at 15 percent O_2. The NOx emission limits specified in the subpart for each turbine while firing fuels other than natural gas, i.e., distillate oil are 75 ppm at 15 percent O_2. For sulfur dioxide (SO_2) emissions, the owner or operator must not burn in the subject stationary combustion turbines any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/mmBtu heat input.

Compliance with the sulfur limit can be demonstrated by combusting oil with a max sulfur of 0.05 weight percent (500 ppmw) or less and natural gas with a total sulfur content of 20 grains or less per 100 standard cubic feet. Ultra low sulfur diesel or kerosene fuel contains a maximum sulfur content of 15ppmw. Pipeline natural gas, as defined in 40 CFR 72.2, contains a maximum total sulfur content of 0.5 grains per 100 scf.

As described above, the NOx and SOx limits proposed for this project are more stringent than what is required in the subpart.

40 CFR Part 60, Subpart Kb

The company intends to construct a new, approximately 300, 000 gallon fixed roof tank for the storage of distillate fuel that this location. The true vapor pressures of kerosene and No. 2 distillate are estimated to be 0.20 kPa and 0.15 kPa at 100°F, respectively. The tank is not subject to the requirements of 40 CFR Part 60, Subpart K_b since the vapor pressures of kerosene or No. 2 diesel are both less than 3.5 kPa.

40 CFR Part 63, Subpart YYYY

The facility is not subject to the requirements of 40 CFR Part 63, Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines since the facility does not have the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. The Title-V operating permit contains hazardous air pollutant emission limits in Section C of the permit to ensure that Subpart YYYY is not applicable to this facility.

Compliance Assurance Monitoring (CAM) Rule

The turbines are subject to the CAM rule since the devices controlling these units have pre-control CO emissions in excess of the major source thresholds; however, the CEMS monitoring is considered presumptively acceptable monitoring and satisfies the requirements of Part 64.

Cross State Transport Rule

Since the turbines are not anticipated to commence operation until after January 1, 2012, the Clean Air Interstate Rule (CAIR) does not apply and the turbines are instead subject to the Cross State Transport Rule. The Cross State Transport Rule requirements have been incorporated under Section E – Source Group Restrictions as Group SG03 – Transport Rule Requirements. A condition is included in Section C of the plan approval that precludes the commencement of turbine operation until on or after January 1, 2012.

25 Pa. Code, Section 129.56 –Storage tanks greater than 40,000 gallons capacity containing VOC's

VOC emissions from the distillate fuel storage tank are estimated to be 0.12 ton per year. Storage tank emissions were estimated using Tanks 4.0.9d software. The distillate storage tank is not subject to the requirements of 129.56 since the vapor pressures of kerosene or No. 2 diesel are both less than 10.5 kPa.

Recommendations

York County Commissioners and Springettsbury Township each received municipal notification on June 6, 2010. The PA Bulletin notice of *intent to issue* the plan approval as well as the local newspaper announcement are in process.

Upon completion of the appropriate notification and review periods (including public, internal and EPA reviews), I recommend that plan approval 67-05009C be issued.

Cc: SCRO, 67-05009C
Permits
York District
EPA

Appendix D. NGCO2 Workbook (Contents Page)

Evaluation of Natural Gas Units

SUMMARIES

Summaries	Summaries

MAIN DATA

NG_CC	Combined Cycle (CC) Units
NG_CT	Simple Cycle (Combustion Turbine (CT)) Units
Questions	Units with "transitional" data (SC to CC or vice versa), and units whose operation mode is in question)

HISTOGRAMS / PROBABILITY CHARTS

ch_CO2Rate_CC	Combined Cycle (CC) Units, All Years
ch_CO2Rate_CT	Simple Cycle (CT) Units, All Years
ch_OpHrs_CT	Simple Cycle (CT) Hours of Operation Histogram
Hist_AvgC02Rates	Probability Chart of Averages of CO2 Rate Per Gross Load, Average of Available Data From 2006-2012, for Units With No CAMD Data Prior to 2006
ch_CO2RateAvg_vs_StartYear	Avg. 2006-2012 CO2 Rate (Lbs/MWh Gross) vs. Apparent In-Service Year
ch_CO2Rate2011_vs_StartYear	2011 CO2 Rate (Lbs/MWh Gross) vs. Apparent In-Service Year

Appendix E. Ecology's Response to Sierra Club's Comments

ECOLOGY'S RESPONSE TO SIERRA CLUB'S COMMENTS ON PROPOSED PSE FREDONIA EXPANSION PROJECT PERMIT NO. PSD-11-05

October 21, 2013

Sierra Club submitted comments on the proposed Puget Sound Energy (PSE) Fredonia Generating Station Expansion Project Prevention of Significant Deterioration (PSD) permit and Technical Support Document (TSD) Permit Number PSD-11-05.

Sierra Club's comments, dated April 17, 2013, were submitted in a letter with two introductory paragraphs followed by seven numbered comments. To see the full comment, please refer to the appendices in the TSD.

The second introductory paragraph of Sierra Club's letter made two statements the Department of Ecology (Ecology) considers comments even though they were not numbered as such. The **first comment** is that the permit application and TSD lack documentation for several critical assertions needed to establish appropriate permit terms and conditions. Specifically, the paragraph notes: "For example, Ecology copies PSE's Table 5-5 into the TSD as Table 14 and includes calculations that are neither sourced nor critically reviewed by Ecology. Ecology should provide all worksheets in Excel or other accessible formatting to the public."

Response: The information submitted in the application was critically reviewed by Ecology. From the information submitted, Ecology determined that PSD permitting was triggered for this project, and went on from there to write the PSD permit. Ecology based the PSD permit, which was public noticed and presented at a public hearing on April 17, 2013, on the materials submitted by PSE. The assumptions made in PSE's Table 5-5 (shown as Table 14 in the TSD and reproduced on the next page of this document for reference), are given in the table notes. This comment does not result in a change in the proposed permit.

The **second comment** in the second introductory paragraph was, "Similarly, PSE's load forecasts and dispatch (electrical distribution) modeling must be provided to verify several critical operating assumptions for the proposed addition to Fredonia."

Response: The Fredonia expansion project is being developed by PSE as an option to provide additional future generating capacity for PSE. According to PSE's 2013 Integrated Resource Plan (IRP), the company will require additional capacity of just over 200 MW starting in 2017. Analysis in the IRP also found that simple cycle combustion turbines are more cost-effective than combined cycle plants for this type of peaker plant resource need.

Dispatch modeling does not accurately predict the use of the turbines, and therefore is not useful here. PSE's proposals to expand the Fredonia Generating Station was not based simply on the results of a quantitative dispatch model, because quantitative dispatch models consider only the economic dispatch of a unit and, in PSE's experience, are prone to significant uncertainties over the life of a project. Those models also fail to consider non-economic factors that significantly influence how often a particular generating unit is dispatched. Those factors include transmission outages, generation outages, fluctuations in output available from intermittent resources such as wind and solar, changes in power demand, the need for system stability support, and the provision of ancillary services. Ecology agrees with PSE's assessment that these factors often cannot be anticipated. PSE needs a power generation project that has the ability to respond, as needed at a reasonable cost, to changing circumstances and future events that cannot be anticipated. This comment does not result in a change in the proposed permit.

Table 14, from the PSE Fredonia TSD, is included below with the assumptions in the table notes. The source of the information is PSE's internal evaluation submitted as part of their application.

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options

	LMS100	LM-6000	7FA.05	5000F4	7FA.04
Emissions Calculations					
Plant Capacity, net (MW)	199.7	165.1	209.4	207.1	182.3
Generation (MW-hr), 200 MW at 7.5% CF[1]	131,400	131,400	131,400	131,400	131,400
Heat rate @ full load (Btu/kWh, HHV)	9,007	9,871	10,145	10,152	10,193
Fuel CO_2 Rate (lb/MMBtu, HHV)[2]	115.9	115.9	115.9	115.9	115.9
Fuel CO_2e Rate (lb/MMBtu, HHV)[3]	116.8	116.8	116.8	116.8	116.8
Plant CO_2e Emissions Rate (lb/MW-hr)	1,052	1,153	1,185	1,186	1,191
Annual CO_2e Emissions (tpy)	69,118	75,748	77,850	77,904	78,219
Emissions Rank (1 = lowest emitting)	1	2	3	4	5
CO_2e Reduction from Base Unit (tpy)	9,101	2,471	368	315	0
Cost Calculations					
Plant Book Life (yrs)	35	35	35	35	35
PSE Discount Rate	8.10%	8.10%	8.10%	8.10%	8.10%
Annual O&M					
Fixed O&M (FOM) ($/kW-yr)	15.71	19.06	11.48	11.76	12.32
First-Year FOM ($/yr)	3,136,522	3,146,952	2,403,015	2,436,339	2,246,140
FOM Escalation Rate[(1)](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
FOM Levelized Cost ($/yr)	4,063,695	4,998,100	3,113,360	3,156,534	2,910,111
Variable O&M (VOM) ($/MW-hr)	3.58	4.34	11.88	10.28	10.68
First Year VOM ($/yr)	470,713	570,584	1,560,650	1,350,846	1,402,785
VOM Escalation Rate[(1)](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
VOM Levelized Cost ($/yr)	609,858	906,221	2,021,987	1,750,164	1,817,457
Fuel ($/MMBtu, HHV)	8.08	8.08	8.08	8.08	8.08
First Year Fuel ($/yr)	9,562,840	10,480,159	10,771,068	10,778,500	10,822,030
Fuel Escalation Rate(%/yr)[4]	3.00%	3.00%	3.00%	3.00%	3.00%
Fuel Levelized Cost ($/yr)	12,389,669	16,644,959	13,955,056	13,964,685	14,021,083
All-In CapEx ($)	279,000,000	274,000,000	198,000,000	191,000,000	185,000,000
Capital Recover Factor	8.67%	8.67%	8.67%	8.67%	8.67%
Annual CapEx ($/yr)	24,182,437	23,749,060	17,161,729	16,555,002	16,034,949
Total Levelized Annual Cost ($/yr)	41,245,660	46,298,340	36,252,133	35,426,384	34,783,600

Table 14. Incremental Emission Reduction Cost Analysis for Five Turbine Options					
	LMS100	LM-6000	7FA.05	5000F4	7FA.04
Levelized Cost (Savings) Over Base ($/yr)	6,462,059	11,514,739	1,468,532	642,784	$0
Incremental Cost-Effectiveness ($/ton CO_2e)	$710	$4,660	$3,987	$2,043	$0

[1] Assuming the project would generate 131,400 MW-hrs of electricity per year for all options.
[2] Assuming natural gas would be used as the fuel.
[3] Based on source testing at PSE's Sumas and Mint Farm Generating Stations in 2009, CO_2 emissions account for approximately 99.27% of total CO_2e emissions.
[4] Assuming an escalation rate of 3% as an average inflationary number. This number falls within the range of historical inflation.

PSE used their internal load forecasts to develop the kind of project the company felt was needed. This information was reviewed by Ecology, and used to develop the PSD permit for the Fredonia expansion project.

This comment did not result in a change in the proposed permit.

Sierra Club's Numbered Comments

1. **GHG BACT requires a GHG emissions rate limit achievable by the most efficient turbine model.**

Response: BACT does not require permit limits based on the most efficient equipment model available within a technology category. Rather, limits are developed on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs of the project proposed by the applicant (as noted in Definitions, 40 CFR 52.21 (b) (12)). Efficiency is an important consideration. However, another consideration applicable to the peaking and load matching generation required by PSE for this project is the ability of the project to quickly adjust its generating capacity rapidly enough to accommodate unpredictable changes in market demand and the availability of power from other sources.

Ecology determined that any of the four turbine options could be permitted and that all four meet all applicable air quality requirements. The BACT discussion is found in Section 3 of the TSD. BACT for GHG emissions is discussed in Section 3.5. Tables 13 and 14 compare the turbine models, and do not translate directly into permit limitations because permit limitations include the effects of other operational parameters and considerations. Other considerations for this proposal include operating hours, loads, and the number and duration of start-ups and shutdowns. The GHG BACT Summary for the combustion turbines is listed in Table 15. Ecology used performance data from the turbine vendors and proposed operation (such as start-ups and shutdowns) to estimate emissions. Emissions estimates for both CH_4 and N_2O used the results of source testing at PSE's Sumas and Mint Farm Generating Stations in 2009.
The proposed BACT limits for each of the four options evaluated for this project are lower than the York Plant Holding Project proposed BACT limits listed in Table 13 of the TSD. The York

Plant Holding Project proposed to restrict their simple cycle combustion turbine to emit less than 1,450 pounds CO_2 per MW-hr, which is higher than any of the four options for PSE's project.

As discussed below, Ecology concludes that any of the four turbine options constitute BACT for this project. All four turbine options are very efficient. It is important to recognize that PSE must consider factors in addition to efficiency when deciding which turbine option will best meet the purpose of this project. Those factors include:

- Reliability: Turbine models exhibit different operating histories and reliability performance both between models and over time as a given technology matures. PSE must feel confident that a chosen turbine model will operate reliably after installation.
- Flexibility: A turbine's ability to start and stop rapidly, as well as to ramp up and down quickly, adds value to PSE. Two smaller turbines may be able to fulfill power demands more economically than a single large turbine. Typically this comes at a cost premium that must be considered at the time of final selection.
- Power Quality: Different turbine generators will exhibit different impacts on the power quality of a given transmission system. During the interconnection process, PSE's transmission contracts group will run computer simulations of the transmission system to determine potential impacts of a proposed addition of generating capacity. Based on system information that will be available at that time, these simulations will estimate potential overloads, system voltage concerns, and system stability. The simulations then develop hypothetical potential transmission upgrades to mitigate any impacts if necessary. It is important for PSE to be able to choose among different turbine options because some turbines may require more extensive system upgrades than others.
- Availability: Demand for new turbines has a great impact on availability, cost, and lead time for delivery. If a given turbine is in heavy demand, it may not be available in time to meet project requirements.

For the Fredonia project, PSE narrowed down their project to four turbine options from a larger set of initial options. PSE's final decision will not only be based on a turbine with superior efficiency, but will also balance the issues discussed above with capital and operating costs. PSE directed their consultant to develop a complex permit application that included four options that operate at similar levels of efficiency. At some point, PSE will make a decision and one of the four options will beat out the others in meeting PSE's performance and economic needs. All four options are very efficient turbines, and Ecology concluded that any of the four options meets the regulatory requirements of the PSD permit program.

This comment does not result in a change to the proposed permit.

a. The permit may not set a weaker GHG limit based on alternate operating scenarios.

Response: Historically, PSD permits have authorized the permit holder to install different equipment options (and either established different criteria pollutant emission limits for each option, or set permit limits based on the higher emitting option). The same approach is appropriate for GHG emissions. Consistent with that approach, EPA Region 6 has recently proposed to issue a PSD permit for the La Paloma Energy Center that would give the permit holder the option of using any of three turbine models (GE 7FA, Siemens SGTF-5000(4), and SGTG-5000F(5)), and would establish different emissions limitations for each turbine option (Draft Statement of Basis Draft PSD Permit for La Paloma Energy Center, LLC, March 2013, <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-draft-sob.pdf>). In addition, several other recent PSD permit applications propose to allow the applicant to choose the actual equipment to be installed at the time of construction. For example, the NRG Texas Power–Cedar Bayou Station Application, dated November 2012, proposes four turbine options for a simple cycle facility: the GE Model 7FA.03, 7FA.04, 7FA.05, or Siemens Westinghouse 5000F (5). The PSE Fredonia expansion project uses a similar approach. Because Ecology has determined that each of the four turbine options proposed by PSE satisfies the BACT requirement, Ecology considers the efficiency differences between the four possible turbines small enough to allow PSE to make a final turbine selection based on business considerations at the time that the project is given final authorization to construct.

As is the case with any new utility project that considers multiple equipment options, PSE's turbine equipment alternatives have differing characteristics which can result in differing annual operating hours. The operating parameters do not constitute alternative operating scenarios as thought of in Title V air operating permits. Ecology is including the operating parameters along with the efficiency of turbines to provide for a clear definition of what equipment and operating parameters are required in the proposed PSD permit. Four options were included in the PSD permit. These four options provide four equipment alternatives along with their respective operating parameters that generate about the same amount of power. Ecology determined all four options meet PSD permitting requirements. In considering how a two turbine option may be used versus a one turbine option, the equipment has slight differences that result in a possible variability in operation. This means that if PSE goes with the two turbine option, there may be times when only one of the two turbines may be run, and very likely will result in more start-ups. Any of the four turbine options proposed satisfy the BACT requirement. The selection of a turbine will not result in a "weaker" limit, but will result in the appropriate limit for the specific turbine that is eventually selected. After PSE chooses the final option to install, Ecology will remove the options not chosen from the permit.

This PSD permit is not intended to be based on "average" or "typical" operating scenarios. PSE determined a reasonable maximum annual operating condition for each turbine model that would avoid adverse air quality impacts, and satisfy PSE's future system needs. PSE estimated maximum annual capacity factors of 26% for the large frame turbines (50000F(4), 7FA.05 and 7FA.04) and 33% for the LMS-100 model turbine, which results in a valid comparison while providing the flexibility required for a peaking scenario.

Ecology requested that PSE analyze the relative cost of GHG emission reduction associated with different combustion turbine models. To better evaluate the relative costs of different turbines, PSE assumed that all turbines would operate at the same capacity factor. To accurately assess the relative costs that would actually be incurred during operation, PSE based its calculations on a capacity factor that reflects the typical long term operations of a peaking facility in the Pacific Northwest, which finds peaking generation units typically operate 5%-10% of the time. PSE concluded that a 7.5% capacity factor was a reasonable assumption to use from the range of 5%-10% in this analysis.

This comment does not result in a change to the proposed permit.

b. BACT requires an emission limitation based on the maximum degree of reduction available.

Response: A determination that requires an emission limitation based only on the maximum degree of reduction available is called a Lowest Achievable Emissions Rate (LAER)[1] determination. LAER is required for projects located in areas that do not meet the National Ambient Air Quality Standard (NAAQS) for a pollutant. As there are no NAAQS for GHGs, LAER for GHGs is not defined.

The PSE Fredonia project is located in an area that is in attainment for all NAAQS. These areas require a control technology determination based on BACT. Chapter B of EPA's New Source Review Workshop Manual (draft October 1990) states on pp. B.1-B.2 that the BACT requirement is defined as:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines 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 pollutant. ...
>
> During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be recommended which would not meet any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and 61 (National Emission Standards for Hazardous Air Pollutants).

This quotation from the NSR Workshop Manual demonstrates that a BACT evaluation includes consideration of several more criteria than just the maximum degree of reduction. Federal guidance requires each PSD permit applicant to implement a "top-down" BACT analysis process for each new or physically or operationally changed emission unit. Ecology has adopted the top-down BACT process for our BACT determinations. This top-down BACT analysis process consists of the five basic steps described below:

[1] As defined in the federal regulation 40 CFR 51.100(o).

- Step 1: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.
- Step 2: Eliminate all technically infeasible control technologies.
- Step 3: Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.
- Step 4: Evaluate most effective controls and document results.
- Step 5: Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

If the applicant proposes to implement the most effective, or "top" available control strategy identified in step 3, it is not necessary to evaluate the most effective controls and document results. See EPA's *Draft New Source Review Workshop Manual*, 1990 (NSR Manual) and PSD and Title V Permitting Guidance for Greenhouse Gases <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf>.

The manual never discusses how to perform the analysis when the emission differences are the result of design differences between different makes and models of the emission unit itself. Throughout the NSR Manual, the BACT analysis is described as an analysis that focuses on categories of control technologies, rather than the comparison of different makes or models of equipment within a particular category (NSR Manual, p. B.23). Significantly, the NSR Manual presents a detailed example of how the BACT analysis should be performed for simple cycle gas turbines firing natural gas. The control technologies evaluated are SCR, water injection, steam injection, low NO_X burners, and SNCR. The manual does not suggest that different models of combustion turbines should be evaluated (NSR Manual, pp. B.58–B.73) Indeed, the manual emphasizes that the BACT analysis should not be used as a basis to "redefine the design of the source" (NSR Manual, p. B.13).

To be considered BACT, a control technology must have been demonstrated or achieved in practice. Cost and feasibility are two additional factors included in a BACT analysis. Ecology uses a top-down process, but one does not just start at the BACT top and stay there. The NSR Manual describes the top-down BACT analysis as one that requires consideration of "air pollution control technologies or techniques" including "inherently lower-polluting processes" (NSR Manual, p. B.5).

Ecology acknowledges that turbine efficiency is a critical piece of determining BACT for combustion turbines. Ecology appropriately considered efficiency, along with the other elements required by the top-down BACT process when setting BACT for the PSE Fredonia project. EPA's guidance on GHG permitting focuses on the evaluation of different categories of technology (EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011). In this GHG guidance, EPA encourages consideration of "technologies or processes that maximize the energy efficiency of the individual emissions unit" (EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011). Two examples were given to illustrate this point. For a proposal to construct a pulverized coal or circulating fluidized bed boiler, the guidance states that the BACT analysis should consider whether more efficient types of boilers that use supercritical and ultra-critical steam pressure designs would be appropriate alternatives. For a proposal to construct a simple cycle gas turbine facility, the guidance states that the BACT analysis should consider whether a combined cycle combustion turbine technology would be an appropriate alternative.

Ecology followed EPA guidance in that it considered different types of technology that could be used in peaking applications, such as simple cycle combustion turbines, reciprocating internal combustion engines, and combined cycle combustion turbines. Reciprocating engine technology was rejected because available engines in this size range have greater emissions, and modeling indicated that they would result in unacceptable ambient air quality impacts. Combined cycle technology was ruled out for this peaking project on technical and commercial risk grounds as stated in the permit application and Ecology's TSD (also see response to Comment 3). These grounds were sufficient for Ecology's BACT analysis findings.

This comment does not result in a change to the proposed permit.

c. The TSD's analysis of incremental emission reduction costs does not comply with BACT requirements.

Response: The Sierra Club is correct that PSD BACT guidance does utilize the total cost comparison as the basis to evaluate cost-effectiveness between control options or differing control efficiencies between control options. However, PSD BACT guidance also looks at incremental emission reduction costs (NSR Manual, pp. B.41–B.44). The NSR Manual states, "The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option." In this case, Ecology determined that the incremental cost analysis, which is identified by EPA as a way to distinguish between otherwise similar control alternatives in deciding BACT, was a permissible way to evaluate the options. Ecology used the incremental cost analysis to determine whether the 7FA.04 turbine should be considered BACT.

This comment does not result in a change to the proposed permit.

d. (found as "a" on page 6 of the comments—appears to be a numbering error)

The TSD's analysis of incremental emission reduction costs is unsupported and incorrect.

Response: As discussed on p. 35 of the TSD, the least efficient make or model is not necessarily the highest annual emitting option. For example, for a peaking facility in which a turbine does not operate all the time, a more efficient make or model may still have higher annual GHG emissions if running more, compared with a less efficient make or model with fewer operating hours (i.e., because of less fuel used). Ecology required PSE to estimate the operating time because this project will not be run on a regular basis. As a result, Ecology considered engine efficiency together with hours of operation during the BACT analysis. For example, given PSE's turbine options, the least efficient engine (7FA.04) generates the fewest annual GHG emissions while the most efficient engine (GE LMS100) generates the largest annual GHG emissions mainly because of more operation hours (i.e., increased fuel use). As noted above in Response 1., 1.a., 1.b., and 1.c.), BACT is a procedure that was carefully followed. As discussed in the response above in 1.c., incremental cost analysis is the proper way to proceed for this project. The support and assumptions for the Incremental Emission Reduction Cost Analysis are provided in the TSD in the notes of Table 14. The all-in capital expenses are listed in Table 14 on p. 35 of the TSD. The costs were provided to PSE, who in turn included these costs in their application. PSE and Ecology based their analyses on these figures, which are the best numbers available. When PSE makes their decision on which turbine to purchase, PSE will be using final prices (among other considerations) to complete their purchase. Ecology does not expect any significant changes based on future updated vendor information.

This comment does not result in a change to the proposed permit.

2. Hours of operation allowed for peaking unit(s) are too high.

a. Peaking units operate less than 2000 hours annually.

Response: In developing the permit, Ecology searched for a definition of peaking units, discussed peaking units with PSE, and concluded that there was not a specific definition for PSD permitting purposes. In addition, Ecology found that it was difficult to compare peaking units in operation because there were differences in the electrical systems where the peaking units were being used. Sierra Club's comment asked why Ecology considered the proposed project a peaking unit when allowing 2,280 to 2,880 hours of operation per year. Although some electrical generating units used less than 2,000 hours per year, this does not constitute a definition of peaker operation. Peakers must respond to demand, which can be much greater during some years. PSE anticipates that the new unit(s) will operate less than 2,000 hours during typical years. PSE's peaking turbine capacity factors vary between 5% and 10% during typical years. Thus, a 7.5% capacity factor was used for PSE's economic analysis in the permit application. This is roughly equivalent to less than 700 hours at full load, or 1400 hours at 50% load. Ecology found on-line a company flyer by Cummins that noted two peaking power plants. One was a diesel peaking unit for low-hour use, and the other a natural gas peaking unit for use ranging from 1,000 to 4,000 hours per year. Thus, peaking units have a range of hours for use, and the PSE proposed natural gas project falls within this range. The bottom line is that the proposed PSE units are not base load units, and will be used to meet peaking demand. The project is described in detail on p. 4 of the TSD.

Within this comment, Sierra Club noted that setting maximum operating hours based on total fuel usage increases the total hours of operation because the calculations assume a compliance margin of hours of operation, but in practice the units will operate much more efficiently allowing even higher annual operating hours than the 2,880 and 2,280 hours proposed. As described on p. 12 of the TSD, allowable emission calculations for each turbine option are based on the anticipated maximum annual hours of operation, which includes peaking mode operations and the anticipated number of unit start-ups and shutdowns each year. The LMS100 option has two turbines so that there may be times that only one turbine might be operating. This could result in this option having more start-ups and shutdowns. Ecology chose to account for the variable operation anticipated for these peaking units by limiting the fuel usage and number of start-ups and shutdowns instead of the hours of operation because emissions are more closely related to fuel use than operating hours. Ecology must include emissions during unit start-ups and shutdowns because emissions may be higher than normal operating conditions. Since the turbine will not run on a predictable schedule like a base load electrical generating unit, an estimate of peaking mode operations, including the number of start-ups and shutdowns, must be made. This means that a turbine that can quickly be brought into service may have more starts and annual operating hours than another unit that takes longer to begin generating electricity. Annual fuel uses were estimated and summarized in Table 4 on p. 12 of the TSD. This is a better approach to analyze a peaking turbine's emissions, as well as giving PSE maximum operating flexibility.

This comment does not result in a change to the proposed permit.

3. Exclusion of combined cycle combustion turbine (CCCTs) is inappropriate.

Response: PSE has consistently stated that the purpose of the Fredonia Generation Station expansion project is to provide approximately 180–210 MW of additional peaking generation capacity for its system. To operate effectively to provide peaking generation capacity, the Fredonia turbine must be able to respond rapidly to changing and often short-term peak power demand on PSE's system. Although the facility will not operate most of the time, fast start and frequent starts and stops are essential for PSE to adapt to changing loads and unanticipated events, including supporting wind generation, peak demand periods, transmission and generation outages, and ancillary service needs through the life of the proposed combustion turbines.

Simple cycle combustion turbines are best suited and more cost-effective for peaking applications. A simple cycle combustion turbine does not have a steam cycle like a combined cycle turbine. So the simple cycle combustion turbine does not have cool or cold water, and boiler tubing to heat as part of the start-up sequence. Unlike a combined cycle system, start-up duration and quantity of emissions during start-up of a simple cycle turbine are unrelated to when the last shutdown occurred. The duration of start-up/shutdown for a simple cycle combustion turbine is relatively short because it is mainly related to bringing the turbine rotors up to speed, lighting the turbine burners, bringing the SCR and oxidation catalysts up to their minimum operating temperatures, and synchronizing the electric generator to the grid.

While the industry is working to develop combined cycle plants that could offer some of these fast-starting peaking abilities; they currently are not cost-effective for this type of peaking application. In connection with its IRP, PSE performed detailed modeling and concluded that CCCT would be significantly more expensive. For further information, see 2013 IRP, p. 5-58, available at: http://pse.com/aboutpse/EngergySupply/Documents/IRP_2013_Chap5.pdf. Although Sierra Club identified instances in which developers are considering installing "fast-start" combined cycle facilities in California, Sierra Club does not provide any information about the expected operations of these facilities, or about whether conditions in California are relevant to PSE's system conditions. Nor has Sierra Club demonstrated that these new technology turbines are reliable when started and stopped frequently. Combined cycle systems experience more wear and tear from thermal cycling than simple cycle turbines as the number of annual starts and stops increases. A fast-start combined cycle design might make sense for a facility operating at much higher capacity factors, but Ecology and PSE are not aware of any utility or developer planning to build a combined cycle facility in order to provide 180 to 210 MW of peak generating capacity that is expected to typically operate at a 7.5% capacity factor. Ecology finds that it is appropriate to not use a CCCT for the Fredonia project.

In addition, EPA's Environmental Appeals Board (EAB) recently considered a case regarding the Pio Pico Energy Center. In this case (In re: Pio Pico Energy Center, PSD Permit No. SD 11-01, PSD Appeal Numbers 12-04 through 12-06, August 2, 2013), the applicant proposed to build a simple cycle generating facility to provide peaking and load-shaping generation. The facility would also support intermittent renewable generation, and would need to have the capability for frequent and fast turbine start-ups. EPA Region 9 considered combined cycle combustion turbine technology in its BACT analysis, but ultimately concluded it was technically infeasible and inapplicable to the proposed source. EPA explained that when assessing the technical feasibility of a control technology, it is appropriate to consider whether the technology may reasonably be deployed on, or is applicable to, the source under consideration. Longer start-up times are not compatible with the operational characteristics of the proposed facility and that these technical difficulties would preclude successful deployment of a combined cycle operation. The EAB upheld this analysis on appeal. This analysis is equally applicable to PSE's proposed Fredonia expansion.

This comment does not result in a change to the proposed permit.

4. **The TSD does not provide sufficient support for the elimination of carbon capture and sequestration (CCS).**

Response: The TSD did provide sufficient support for the elimination of CCS. In Section 3.5.1 on p. 29 of the TSD, Ecology found that voluntary BACT analyses of CCS were performed for two projects permitted in late 2010: the Calpine Russell City Energy Center Project, which includes a combined cycle combustion turbine project, and Portland General Electric's Port Westward II Project, which includes a simple cycle GE LMS100 gas turbine. In both BACT analyses, CCS was found to be unavailable or infeasible in practice. In addition, PSE indentified a PSD permit (SE-09-01) issued to Palmdale Hybrid Power Project in southern California by EPA Region 9 on October 18, 2011, involving GHG BACT analyses. This proposed project includes thermal solar technology and two combined cycle GE Frame 7FA CCCTs. The project application and permitting documents considered two GHG control technologies. One was the use of new thermally efficient CCTs, and, second, the use of CCS. CCS was eliminated as technically infeasible for the project and was not considered beyond BACT step 2.

In Ecology's independent BACT review, the following three additional combine cycle generating facilities were identified and evaluated.

1. Pacificorp Lake Side Power Plant (PLSPP), UT (DAQE-AN0130310010-11)
2. Lower Colorado River Authority (LCRA) Thomas C Ferguson plant (PSD-TX-1244-GHG)
3. Pioneer Valley Energy Center (PVEC) Westfield, MA (EPA draft PSD 052-042-MA15)

The PLSPP permit was issued by Utah Department of Environmental Quality (DEQ) on May 4, 2011. The Utah DEQ concluded that high efficiency combustion turbine and HRSG design are the BACT for GHG. The LCRA permit was issued by EPA Region 6 on November 10, 2011. Region 6 concluded that there is no commercially available CCS system to proper scale to LCRA in the near term. In addition, even if technically feasible, the option has been eliminated based on a cost-effectiveness basis. The PVEC draft permit prepared by EPA Region 1 was available for public comment from December 5, 2011, to January 24, 2012. EPA Region 1 eliminated CCS technology for PVEC's proposed project as GHG BACT due to the energy, environmental, and economic impacts.

Ecology also identified four other combustion turbine permits involving GHG emissions, which are under review by state and local permitting authorities at the time of preparing this document and have received EPA written comments. These projects are the Effingham County Power Project (GA, DNR), Cricket Valley Energy Project (NY, DEC), York Plant Holding Project (PA, DEP), and Wolverine Power-Sumpter Project (MI, DEQ). The use of CCS has been eliminated in these draft permits as BACT for GHG.

Within the PSE's permit application BACT analysis, the applicant proposed to eliminate CCS because CO_2 capture is not technically feasible for combustion turbines. In their application, PSE examined a list of 14 active and potential CCS projects (predominantly by the pre-combustion capture technology and only one by the post-combustion capture technology) published by the Global CCS Institute to see if any are similar to the proposed simple cycle gas turbine options. PSE also reviewed seven other post-combustion CO_2 capture and storage demonstration projects that were built and operated over the years, but are no longer in operation or on hold due to economic reasons, including a demonstration scale capture technology at a Florida Power and Light (FP&L) natural gas combine cycle turbine power plant in Bellingham, Massachusetts. The increased natural gas prices in 2004 to 2005 forced the FP&L power plant to operate in a peak load shaving mode, which rendered the CO_2 capture plant uneconomical after 14 years of operation (1991–2005). During this time, only a fraction of CO_2 from gas-turbine exhaust was captured and provided for off-site sale. Sequestration was not attempted at the Bellingham, Massachusetts plant.

The applicant also identified four potential sequestration options: enhanced oil recovery (EOR), geologic sequestration, silicate mineral reactions, and industrial reuse. In the Pacific Northwest, EOR opportunities do not exist due to the lack of oil and gas production areas. Pipelines do not exist for the transportation of CO_2 to distant oil and gas production areas to provide for EOR. Geologic sequestration, including deep saline formation, deep basalt formations, and the tectonic subduction zone, was also explored for this project and none of them is a viable option and/or within a reasonable distance of the project site (200 miles or more) in addition to the fact that two of the three approaches (deep basalt formations and injection in tectonic subduction zones) have not been demonstrated in practice. Silicate mineral reactions are also infeasible because the mineral deposit is undeveloped and there is no existing rail transport infrastructure to transport the minerals to and from the power plant site or developed disposal sites to receive the reacted minerals.

PSE performed a qualitative cost analysis for carbon capture and sequestration. PSE considered cost per ton of CO_2 avoided prepared by others, and then compared these projects' specifications with the proposed PSE Fredonia Project specifications. PSE concluded that the fewer operating hours, additional steam requirement for the CO_2 capture system, heat rejection system with a bigger cooling duty, no available saline formation within a 50-mile radius of the facility, and a smaller size of a CCS system required for the PSE Fredonia Project will cause the cost per ton of CO_2 avoided to be much higher than currently acceptable economic thresholds. Carbon capture alone is demonstrated not to be economically viable for the PSE Fredonia Project. Adding the cost of any sequestration would add significantly to the Fredonia Generating Station Expansion Project's overall cost. Ecology thoroughly considered CCS systems, and concludes that CCS systems would not be cost-effective for the proposed project at this time.

This comment does not result in a change in the proposed permit.

a. Availability of saline formations

Response: BACT requires control technology that is available. In order for CCS to be required as BACT, sequestration storage areas, including saline formations, have to be currently viable. Although the WESTCARB atlas indicates certain geologic structures have a potential for carbon storage, much more technical investigation and development must be done before a CCS commercial operation can be considered viable and available for this project. A review of the 2012 edition of the Department of Energy's Carbon Utilization and Storage Atlas, Fourth Edition (December 2012)[2] confirms that no commercial CCS projects using geologic saline sequestration are operational. The Big Sky Carbon Sequestration Partnership is in the process of investigating the potential of basalt strata to store CO_2 in eastern Washington, but that study will only indicate the site's potential for carbon storage. No commercial CCS operation is currently planned for eastern Washington, or any other site in Washington. Saline sequestration is not listed as a control option in the EPA RACT/BACT/LAER Clearinghouse, has not been demonstrated in practice, and is not available as a commercially proven process. Therefore, saline sequestration was not considered as available for GHG BACT for Fredonia.

This comment did not result in a change in the proposed permit.

[2] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, December 2012, available at <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/Atlas-IV-2012.pdf>.

b. Cost of CCS

Response: Ecology's use of the applicant's cost estimates was an attempt to develop a cost estimate for a project that is effectively impossible to cost using normal procedures. The normal BACT cost determination process is built around the concept of comparing a project's site-specific pollutant control costs to the cost borne by other sources of the same type in applying that control alternative. Ecology tried, but could not find any CCS projects of the same type for comparison.

When calculating the cost-effectiveness of CCS at Fredonia, two cost figures must be determined: (1) The annualized cost of the CCS system to be installed and operated at Fredonia divided by the number of tons of pollutant removed, and (2) the annual $/ton cost-effectiveness threshold that determines whether the CCS installation is cost-effective or not. Data provided in IPCC's *Carbon Dioxide Capture* report [3] indicate that the capital cost of the Fredonia expansion project would be nearly doubled by the addition of CO_2 capture technology. The capital cost increase, costs to operate capture equipment, and costs to transport and store the CO_2 would make the project economically infeasible. Ecology found no CCS process in commercial operation on gas-fired turbines that could be compared to the Fredonia project.

The wide range of estimates for the social cost of carbon (from $28 up to $893) shows the difficulty in attempting to cost out an unproven technology. It is difficult to find costs because of lack of CCS applications for gas turbine power plants and the amount of uncertainty in attempting to apply this lack of information to the Fredonia project. Therefore, Ecology's use of costs found from the U.S. Department of Energy is appropriate.

This comment did not result in a change in the proposed permit.[3]

5. PM limits are too high.

Response: The emissions of PM from the Fredonia project are largely determined by the amount of fuel burned and the concentration of sulfur in the fuel. Long-term monitoring records of the total sulfur content of the natural gas imported from Canada into western Washington shows this gas generally has higher sulfur content than natural gas from the rest of the United States. PSE analyzed seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) for the Northwest Pipeline compressor station at Sumas, WA. The maximum 365-day rolling average was 1.10 grains of sulfur per 100 standard cubic feet of natural gas, and the highest 99th percentile daily sulfur concentration measured at Sumas during the seven year period was 3.23 grains per 100 standard cubic feet. In comparison, in California, the pipeline natural gas typically contains much less than one grain of sulfur per 100 standard cubic feet. Further details are presented in the TSD on p. 20. It is not necessary to review stack tests of similar uncontrolled natural gas-fired units that use Canadian natural gas because of the fuel differences. Given the sulfur content of the fuel for this facility, Ecology has concluded the PM limits are appropriate.

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[3] IPCC, 2005, *Carbon Dioxide Capture and Sequestration*, edited by Bert Metz, Ogunlande Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer, Cambridge University Press, Chapter 8–Cost and Economic Potential, <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter8.pdf>.

This comment did not result in a change in the proposed permit.

6. The air quality analysis is insufficient.

Response: The Sierra Club correctly notes that the air quality analysis should have included a comparison of the SILs to background and emissions from nearby and area sources in the area. The background concentrations affecting the Fredonia Power Generating Station are:

Species	Background	SIL	NAAQS
$PM_{2.5}$ 24 hr $\mu g/m^3$	13	1.2	35
$PM_{2.5}$ annual $\mu g/m^3$	6	0.3	12
PM_{10} 24-hr $\mu g/m^3$	43	1.04	150
CO 1 hr ppm	1.323	1.11	35.0
CO 8 hr ppm	0.922	0.278	9.0
NO_2 1 hr ppb	33		100
NO_2 annual ppb	8	0.53	53

The above table shows that background is very low compared to the NAAQS, and that adding the SILs to background does not come close to the NAAQS. In addition, on p. 46 of the TSD, Ecology demonstrates that the maximum impacts occur at locations well within the receptor grids and not on the borders, which would necessitate further grid analyses. As a result, no additional modeling was performed on the finer grid spacing. Ecology appropriately concluded that a full NAAQS analysis and an increment analysis were not required for any pollutant. Ecology found that the SIL and background levels are not close to violating one of the NAAQS. In addition, the facility where the turbine is proposed to be located is in a rural area that has few industrial neighbors.

This comment did not result in a change in the proposed permit. However, the TSD will be amended to add the above discussion concerning the background concentrations of NAAQS and SILs.

7. No consideration of secondary $PM_{2.5}$ formation.

Response: EPA guidance (40 CFR App. W) encourages agencies to consider secondary $PM_{2.5}$ in areas where $PM_{2.5}$ is a problem, such as nonattainment areas and areas close to or upwind of nonattainment areas. 40 C.F.R. pt. 51 app. W § 5.2.2.1.a "Control agencies with jurisdiction over areas with secondary $PM_{2.5}$ problems are encouraged to use models which integrate chemical and physical processes important in the formation, decay and transport of these species (e.g., Models-3/CMAQ or REMSAD)." The area where the Fredonia plant is located is in attainment of all the NAAQS.

Unlike in the eastern United States and areas of California, secondary PM in the Puget Sound area is a minor contributor to $PM_{2.5}$ concentrations during the winter when high $PM_{2.5}$ concentrations are observed. Marysville is the closest monitoring site with data. On 17 days since 2009 when $PM_{2.5}$ levels exceeded 15 $\mu g/m^3$ in Marysville, aerosol nitrate (which is the most abundant secondary inorganic aerosol species measured) made up an average of 5% of the total $PM_{2.5}$, and never exceeded 15 percent.

All of the secondary $PM_{2.5}$ formed from emissions from the Fredonia project is formed from the NO_X emitted by the project. Therefore, the amount of NO_X emitted by the project provides the upper limit for the amount of secondary $PM_{2.5}$ that can form from the project's emissions. Because the PM and NO_X mass emissions from the proposed facility are roughly the same, the maximum expected secondary $PM_{2.5}$ cannot exceed the amount of primary $PM_{2.5}$ produced. So, the total primary $PM_{2.5}$ + NO_X caused $PM_{2.5}$ cannot exceed a total of 2.3 $\mu g/m^3$. However, in reality the $PM_{2.5}$ emissions and impacts will likely be less, and result in $PM_{2.5}$ (both primary and secondary) that will remain below the currently accepted de minimis level. Therefore, Ecology included only the impacts from primary PM_{10} and $PM_{2.5}$ in the analysis.

This comment did not result in a change in the proposed permit.

ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
ALW	Alpine Wilderness
AQIA	air quality impacts analysis
AQRV	air quality related values
ASIL	acceptable source impact level
BACT	best available control technology
BART	best available retrofit technology
bhp	brake-horsepower
bkw	brake-kilowatt
CAA	Clean Air Act
CARB	California Air Resources Board
CCCT	combine cycle combustion turbine
CCS	carbon capture and sequestration
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
DAT	deposition analysis threshold
DC	direct current
DCS	distributed control system
DLN	dry-low NO_X
Ecology	Washington State Department of Ecology
EOR	enhanced oil recovery
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FGS	Fredonia Generating Station
FLAG	Federal Land Managers' Air Quality Relative Values Workgroup
FLM	Federal Land Manager
FR	Federal Register
GE	General Electric

GHG	greenhouse gas
GPW	Glacier Peak Wilderness
gr	grains
GWP	global warming potential
H_2SO_4	sulfuric acid mist
HAPs	hazardous air pollutants
hr/yr	hours per year
kV	kilovolt
kW	kilowatt
LAC	level of acceptable change
LCRA	Lower Colorado River Authority
MACT	maximum achievable control technology
MSA	Magnuson-Stevens Act
MSL	mean sea level
MTB	Mt. Baker Wilderness Area
MW	megawatts
N	total nitrogen
NAAQS	National Ambient Air Quality Standards
NCNP	North Cascades National Park
NESHAP	National Emission Standards for Hazardous Air Pollutants
NG	natural gas
NOC	Notice of Construction
NO_X	nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	new source review
NWCAA	Northwest Clean Air Agency
ONP	Olympic National Park
Pb	lead
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in diameter
$PM_{2.5}$	particulate matter less than 2.5 micrometers in diameter

ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration
PSE	Puget Sound Energy
PTE	potential to emit
PVEC	Pioneer Valley Energy Center
Q/d	emissions to distance
RBLC	RACT/BACT/LAER Clearinghouse
S	total sulfur
SCR	selective catalytic reduction
SEPA	State Environmental Policy Act
SER	significant emission rate
SF_6	sulfur hexafluoride
SIL	significant impact level
SQER	small quantity emission rate
SUSD	start-up and shutdown
SWCAA	Southwest Clean Air Agency
TAP	toxic air pollutant
tpy	tons per year
ULSD	ultra-low sulfur diesel
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
VAC	voltage alternating current
VDC	voltage direct current
WAC	Washington Administrative Code