APPENDIX G

Prevention of Significant Deterioration and Notice of Construction Permit Application

G.1 Introduction

Starbuck Power Company, L.L.C. (SPC), proposes to construct a nominal 1,200-megawatt (MW), natural-gas-fired, combustion turbine generation plant in southeastern Washington. The generation plant will occupy the southeast portion of a 100-acre site located about 6 miles northeast of the Town of Starbuck in Columbia County.

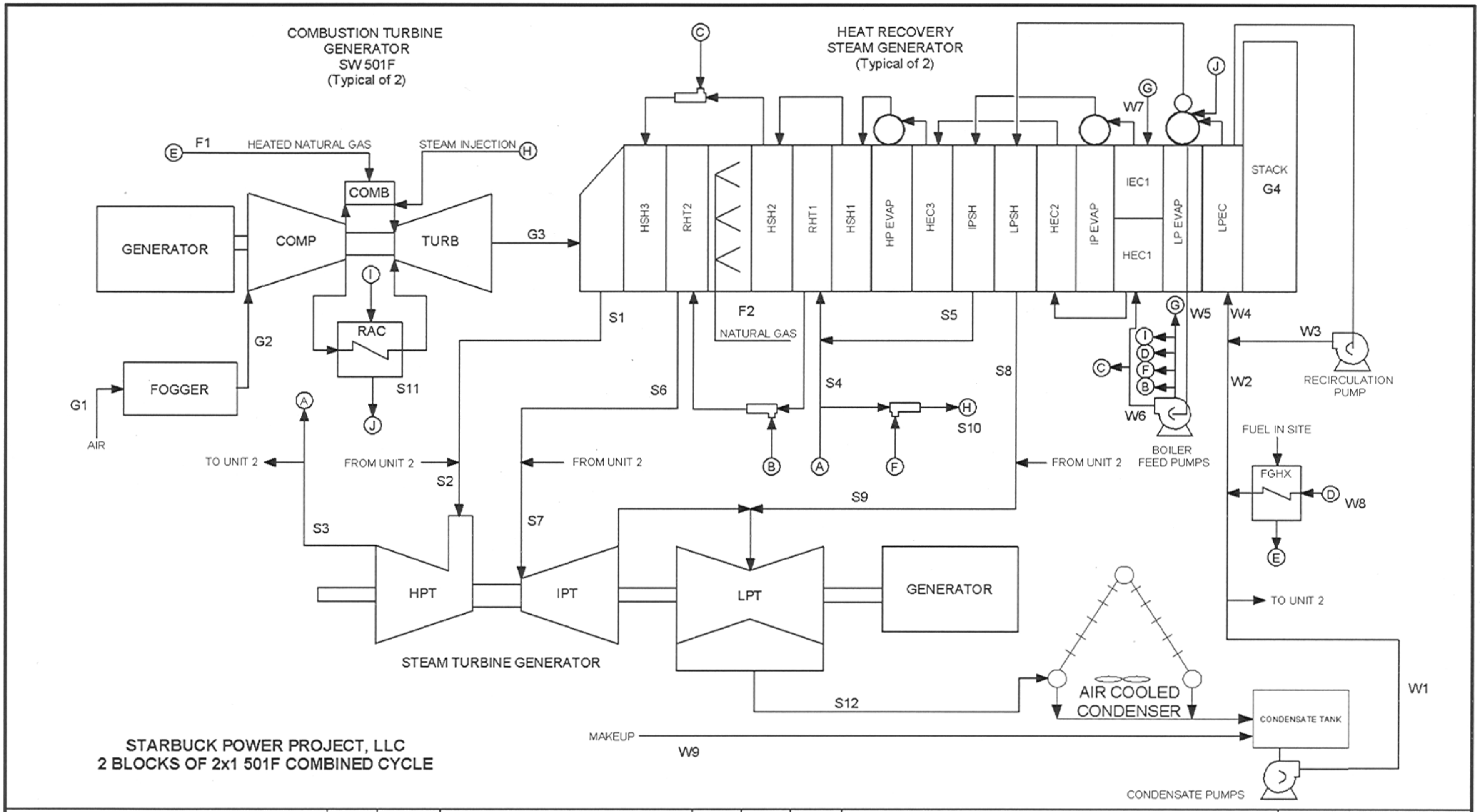
This application is being submitted to satisfy all applicable new source review (NSR) requirements; namely, the prevention of significant deterioration (PSD) rules and notice of construction (NOC) requirements, 463-42-385 *Washington Administrative Code* (WAC) (PSD Application), 40 *Code of Federal Regulations* (CFR) 52.21 (PSD Rules), 173-400-113 WAC (NSR requirements, adopted by reference in 463-39-005 WAC), and 173-460-040 WAC (NSR requirements for toxic air pollutant [TAP] sources). Applicable emission standards are described in Section G.2. An in-depth air quality impact assessment is in Section G.3. The best available control technology (BACT) analysis is presented in Attachments E and F.

The Energy Facility Site Evaluation Council (EFSEC) and U.S. Environmental Protection Agency (EPA) are the co-permitting authorities for the PSD portion of the permit, because EPA has retained jurisdiction over the oxides of nitrogen (NO_X) increment. EFSEC is the permitting authority for the NOC.

G.1.1 Project Information

As proposed, the Starbuck Power Project (SPP) will generate approximately 1,200 MW of electrical power using combined-cycle combustion gas turbines (CGTs), heat recovery steam generators (HRSGs), steam turbine-generators (STGs), and air-cooled condensers. The generation plant will include four sets of combustion turbines, four three-pressure HRSGs equipped with supplemental duct firing, two STGs, two air-cooled condensers, and associated support equipment. Other key generation plant facilities will include the switchyard, control and administration facilities, parking and transfer areas for a mobile water treatment facility, water storage facilities, and a gas metering station.

Figure G-1 provides a simplified view of the electricity-generating process at the generation plant. The electrical generation equipment will be arranged in two “power blocks,” each in a “two-on-one” configuration, in which each of two CGTs will be directly connected to an electric generator and an HRSG. Steam produced by the two HRSGs will be combined and directed to a single STG.



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NO.	DATE	REVISION	DWN	CK	APP	STARBUCK HEAT BALANCE DIAGRAM	B&V Project Number
0	06/20/01	0	AL			*Black & Veatch*	096344.0025

FIGURE G-1

Process Flow Diagram
Application for Site Certification

STARBUCK POWER PROJECT
STARBUCK, WASHINGTON

G.1.2 Construction Schedule

Construction is scheduled to begin in fall-winter 2002, provided all approvals have been received. Construction is anticipated to take approximately 24 months. Operations are scheduled to begin sometime between the end of 2004 and the beginning of 2005.

G.1.3 Summary of Findings

The generation plant will meet all state and federal requirements regarding air emissions and impacts. The equipment will meet all emission controls requirements including those prescribed by the state and federal regulations as BACT. Air quality impacts have been shown to comply with all applicable ambient air quality standards. Impacts to other criteria, including impacts to distant Class I areas, have been shown to be below regulatory thresholds established by EPA and the federal land managers and are considered to be insignificant. TAP emissions have been shown to be below the small quantity emission rates or the applicable acceptable source impact levels defined by regulation.

G.2 Applicable Standards

This section discusses the various federal and state air quality rules, regulations, and guidelines that apply to the SPP. Relevant information about the requirements of these programs and various emission standards, ambient air quality standards, hazardous air pollutant (HAP) regulations, and TAP regulations that are applicable to the SPP are provided in the following sections.

G.2.1 Emission Standards

G.2.1.1 New Source Performance Standards

EPA has established performance standards for various types of air pollution sources in 40 CFR Part 60. They are commonly referred to as the *New Source Performance Standards* (NSPS) and usually represent a minimum level of control that is required on a new source. Most of the NSPS have been adopted by reference in 173-400-115 WAC.

40 CFR Part 60, Subpart GG provides the standards of performance for stationary gas turbines. The combustion turbines associated with the generation plant will be considered electric utility stationary gas turbines because more than one-third of their potential electrical output capacity will be supplied to a utility power distribution system for sale. The NSPS limit the sulfur dioxide (SO_2) emissions in the exhaust gas to less than 0.015 percent by volume at 15 percent oxygen and on a dry basis. The NSPS also restrict burning of any fuel that contains sulfur in excess of 0.8 percent by weight in a stationary gas turbine. The emissions of NO_X also are restricted based on the following formula provided in 40 CFR 60.332(a)(1):

$$NO_X \text{ (\% by volume at 15\% } O_2\text{, dry basis)} = 0.0075 * (14.4/Y) + F$$

where, Y is the heat rate in kilojoules per watt hour, and

F is the NO_X emission allowance for fuel-bound nitrogen.

The emission limits for NO_X and SO_2, based on the use of BACT, are much more stringent than the NSPS emission limits. As shown in Section G.3.3.3, the proposed emission limits for NO_X and SO_2 emissions from the combustion turbines at the generation plant after the application of BACT are much lower than the emission limits allowed by the NSPS.

For sources that use water injection to control NO_X emissions, 40 CFR Part 60.334(a) requires the source to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water-to-fuel being fired in the turbine. The source also is required to monitor the sulfur and nitrogen content of natural gas provided by the pipeline on a daily basis.

When the duct burners are in operation, the HRSGs are subject to the requirements of 40 CFR Part 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978. Subpart Da applies to each electric utility steam generating unit that is capable of combusting more than 73 MW (250 million British thermal units/hour [MMBtu/hr]) heat input of fossil fuel. The duct burners burn natural gas only and do not burn any solid, liquid, or other gaseous fuel. The NSPS limit particulate matter (PM) emissions to less than 13 nanograms per joule (ng/J) or 0.03 pound per million Btu (lb/MMBtu) heat input. The NSPS also limit SO_2 and NO_X emissions to less than 0.20 lb/MMBtu heat input. These limits do not apply during periods of startup, shutdown, or malfunction. Emissions from the duct burners combine with the emissions from the combustion turbines and generally are controlled using the same control technology that is used for controlling emissions from the combustion turbines. As shown in Section G.3.3.3, the proposed emission limits for PM, NO_X, and SO_2 for combined emissions from combustion turbines and duct burners after the application of BACT are much lower than the emission limits allowed by the NSPS.

In addition, 40 CFR Part 60, Subpart A provides the general provisions of NSPS that are applicable to any source subject to NSPS, while 40 CFR Part 60.7 provides the notification and recordkeeping requirements. The source is required to notify the Washington State Department of Ecology (Ecology) and EPA of the anticipated initial startup date, the actual startup date, any changes to the facility that affect emissions, and schedule for demonstration of continuous monitoring system performance. The source is required to keep records of the occurrence and duration of any startup, shutdown, or malfunction of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. The source also is required to submit excess emissions and monitoring systems performance reports.

G.2.1.2 Washington Department of Ecology Emission Standards

Emission limits have been established by Ecology and adopted by EFSEC. 173-400-040 WAC provides the general standards for maximum emissions from various sources and emission units. All emission units are required to use reasonably available control technology (RACT). Visible emissions generally should be less than 20 percent opacity except for 3 minutes in any 1 hour, and SO_2 content in the exhaust gas should not be more than 1,000 parts per million (ppm) on a dry basis, corrected to 7 percent oxygen, and based on an hourly average. 173-400-040 WAC also establishes standards for PM fallout, fugitive emissions, and odors. 173-400-050 WAC provides the emission standards for combustion and incineration units. The PM emissions are limited to 0.1 grain per dry standard cubic foot (gr/dscf) or 0.23 gram per dry cubic meter (g/m^3) at standard conditions, corrected to 7 percent oxygen. As shown in Section G.3.3.3, the PM and SO_2 emissions from all emission units at the generation plant are proposed to be well below the emission limits provided in 173-400-040 WAC and 173-400-050 WAC .

G.2.2 Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) established by EPA are provided in 40 CFR Part 50. For some pollutants, both primary and secondary ambient air quality standards exist. Primary NAAQS define the levels of air quality that EPA has determined to be necessary for protecting the public health with an adequate margin of safety. Secondary NAAQS define the levels of air quality that EPA has determined to be necessary for protecting the public welfare from any known or anticipated adverse effects of a pollutant.

Ecology has ambient air quality standards for PM, sulfur oxides, radionuclides, and fluorides, which are in 173-470, 173-474, 173-480, and 173-481 WAC, respectively. Ambient air quality standards for carbon monoxide (CO), ozone (O_3), and nitrogen dioxide (NO_2) are in 173-475 WAC .

Table G-1 summarizes applicable ambient air quality standards established by EPA and Ecology.

TABLE G-1
Ambient Air Quality Standards [a]

Pollutant	National Primary	National Secondary	Ecology
Total Suspended Particulates (TSP)			
24-hour Average (µg/m^3)	-	-	150
Annual Geometric Mean (µg/m^3)	-	-	60
Particulate Matter (PM_{10})			
24-hour Average (µg/m^3)	150	150	150
Annual Arithmetic Mean (µg/m^3)	50	50	50
Sulfur Oxides (SO_X)			
1-hour Average (ppm)	-	-	0.40[b] (as SO_2)
3-hour Average (ppm)	-	0.50 (as SO_2)	-
24-hour Average (ppm)	0.14 (as SO_2)	-	0.10 (as SO_2)
Annual Arithmetic Mean (ppm)	0.03 (as SO_2)	-	0.02 (annual average as SO_2)
Carbon Monoxide (CO)			
1-hour Average (ppm)	35	-	35
1-hour Average (mg/m^3)	40	-	40
8-hour Average (ppm)	9	-	9
8-hour Average (mg/m^3)	10	-	10
Ozone (O_3)			
1-hour Average (ppm)	0.12	0.12	0.12
1-hour Average (mg/m^3)	235	235	235
8-hour Average (ppm)	0.08	0.08	0.08

TABLE G-1
Ambient Air Quality Standards [a]

Pollutant	National Primary	National Secondary	Ecology
Nitrogen Dioxide (NO_2)			
Annual Arithmetic Mean (ppm)	0.053	0.053	0.05
Annual Arithmetic Mean (µg/m^3)	100	100	100
Fluorides (as HF)			
12-hour Average (µg/m^3)	-	-	3.70
24-hour Average (µg/m^3)	-	-	2.90
7-day Average (µg/m^3)	-	-	1.70
30-day Average	-	-	0.84
March 1 – October 31 Period Average	-	-	0.50
Lead (Pb)			
Quarterly Arithmetic Mean (µg/m^3)	1.5	1.5	1.5

mg/m^3 = milligrams per cubic meter.
µg/m^3 = micrograms per cubic meter.
ppm = parts per million.
HF = hydrogen fluorides.

[a] Annual ambient air quality standards should never be exceeded. Short-term ambient air quality standards should not exceed more than once per year, unless otherwise noted.

[b] 0.40 ppm should not be exceeded more than once per 1-year period. There is also a 1-hour average standard of 0.25 ppm for SO_X, which should not be exceeded more than twice in a consecutive 7-day period.

G.2.3 Hazardous Air Pollutant Regulations

173-400-075 WAC provides the emission standards for sources emitting HAPs. The section adopts by reference the National Emission Standards for Hazardous Air Pollutants (NESHAP) provided in 40 CFR Part 61 and maximum achievable control technology (MACT) standards provided in 40 CFR Part 63. The facility will not be a “major source” of HAPs because maximum potential HAP emissions from various emission units at the generation plant are less than 10 tons per year for a single HAP and less than 25 tons per year for a combination of HAPs. Therefore, none of the MACT standards that already have been promulgated and are provided in 40 CFR Part 63 are applicable to the emission units at the generation plant. For the same reason, the case-by-case MACT requirements under Sections 112(g) and 112(j) of the Clean Air Act for stationary combustion turbines and waste heat recovery units are also not applicable to the CGTs and duct burners associated with the HRSGs. The NESHAPs provided in 40 CFR Part 61 also are not applicable to the various emission units at the generation plant.

G.2.4 Toxic Air Pollutant Regulations

New sources emitting TAPs are subject to the requirements of 173-460 WAC. TAPs include carcinogens and noncarcinogens listed in 173-460-150 WAC and 173-460-160 WAC. The acceptable source impact levels (ASILs) for the various Class A and Class B TAPs also are provided in 173-460-150 and 173-460-160 WAC. The risk-based ASIL for a Class A TAP means an annual average concentration that may cause an increased cancer risk of 1 in 1 million. ASILs for some of the Class A TAPs are based on 24-hour average concentrations instead of annual average concentrations. The threshold-based ASIL for a Class B TAP is determined by dividing the worker exposure limit (threshold limit value-time weighted average [TLV-TWA]) by 300. All of the ASILs for Class B TAPs are based on 24-hour average concentrations.

New sources emitting TAPs are required to use the best available control technology for air toxic compounds (T-BACT) for controlling emissions of the TAPs. In addition, the source is required to demonstrate that the TAP emissions after use of T-BACT are sufficiently low to protect human health and safety from potential carcinogenic and/or other toxic effects. The source is required to complete an ASIL analysis for the Class A and Class B TAPs. The maximum incremental ambient air impact levels should not exceed the ASILs for the various Class A and Class B TAPs. If compliance cannot be demonstrated after completing the ASIL analysis, the source may submit a petition requesting a second-tier analysis evaluation to determine a means of compliance by establishing allowable emissions for the source. The source is required to submit a health impact assessment along with its petition for second-tier analysis evaluation. The source also may submit a request for a risk management decision to allow it to emit TAPs at levels that are likely to result in an increased cancer risk of more than 1 in 100,000. The request for a risk management decision can be submitted concurrently with the petition for second-tier analysis evaluation.

The generation plant has the potential to emit small quantities of TAPs that are covered by these regulations. Benzene, toluene, formaldehyde, and other organic compounds associated with the combustion of natural gas will be released into the atmosphere. In addition, use of selective catalytic reduction (SCR) as the BACT for controlling NO_X emissions from combustion turbines and duct burners results in ammonia emissions commonly referred to as ammonia slip. Section G.3.3.3 provides detailed information about the emissions of various TAPs from combustion of natural gas in the combustion turbines and duct burners and from combustion of diesel fuel in the fire pump at the generation plant.

G.2.5 Permitting Requirements

173-400-110 WAC provides NSR regulations and requires any new source to submit an NOC application and obtain an order of approval before the start of construction. 173-400-113 WAC provides the requirements for new sources in attainment or unclassifiable areas and requires the new source to employ BACT for all pollutants whose emissions would increase. Because the generation plant is classified as a new major stationary source subject to PSD requirements, this is a combined PSD and NOC permit application.

173-401 WAC establishes the requirements for the state air operating permit program consistent with the requirements of Title V of the Clean Air Act (CAA). Per the requirements of 173-401-500(3)(c) WAC, new sources that start operation after EPA approval of the state operating permit program are required to file a complete application to obtain the Chapter 401 permit within 12 months after operation begins. A Title V air operating permit application will be submitted to EFSEC within 12 months of the starting date for operations at the generation plant.

173-406 WAC establishes acid rain regulations that are consistent with the requirements of Title IV of the CAA. In accordance with the requirements of 173-406-301(2)(b) WAC , the designated representative of the affected source is required to submit a complete acid rain permit application to the permitting authority at least 24 months before the date on which the affected source commences operation. An acid rain permit application will be submitted to EFSEC at least 24 months before the anticipated startup date for the generation plant.

G.2.6 Prevention of Significant Deterioration

The state PSD regulations in 173-400-141 WAC incorporate by reference various subparts of the federal PSD regulations. EPA has not, however, approved this state regulation into the State Implementation Plan (SIP), instead incorporating by reference into the Washington SIP the federal PSD of air quality regulations (40 CFR 52.21). PSD regulations govern sources located in those areas where the existing ambient air quality is better than the ambient air quality standards and are meant to ensure that the ambient air quality in these areas does not deteriorate significantly due to the construction of a new source or modification of an existing source.

PSD regulations have established ambient air increments, which limit the increase in pollutant concentration over the baseline concentration for particulates less than 10 microns in diameter (PM_{10}), SO_2, and NO_2. Ambient air increments have been established for three land classifications: areas designated as Class I, Class II, or Class III. The most stringent ambient air increments apply to Class I areas, which include certain specified wilderness areas and national parks. Table G-2 shows the ambient air increments for Class I, Class II, and Class III areas.

TABLE G-2
Ambient Air Increments

Pollutant	Class I Area	Class II Area	Class III Area
Particulate Matter (PM_{10})			
24-hour Maximum (µg/m^3)	8	30	60
Annual Arithmetic Mean (µg/m^3)	4	17	34
Sulfur Dioxide (SO_2)			
3-hour Maximum (µg/m^3)	25	512	700
24-hour Maximum (µg/m^3)	5	91	182
Annual Arithmetic Mean (µg/m^3)	2	20	40
Nitrogen Dioxide (NO_2)			
Annual Arithmetic Mean (µg/m^3)	2.5	25	50

µg/m^3 = micrograms per cubic meter.

G.2.7 PSD Applicability

The generation plant is in one of the 26 source categories (fossil-fuel-fired steam electric plants of more than 250 MMBtu/hr heat input) listed in 40 CFR Part 52.21(b)(1)(i)(a) and has the potential to emit more than 100 tons per year of a regulated air pollutant. It will be classified as a new major stationary source and will be subject to PSD regulations provided in 40 CFR Part 52.21. Once subject to the PSD regulations, emissions of all regulated air pollutants that exceed specific significant emission thresholds must be taken into consideration. Significant emission thresholds are provided in 40 CFR Part 52.21(b)(23)(i).

Table G-3 summarizes the generation plant emissions. As shown in Table G-3, annual emissions of PM (PM and PM_{10}), SO_2, CO, NO_X, and volatile organic compounds (VOCs) will exceed the significant emission thresholds that trigger PSD review. PSD regulations require application of BACT for each regulated air pollutant having the potential to emit more than the significant emission threshold. The source also is required to demonstrate that the allowable emission increases would not cause an exceedance of the ambient air quality standards and PSD ambient air increments.

TABLE G-3
Comparison of Maximum Annual Criteria Pollutant Emissions with Significant Emission Rates

Pollutant	Significant Emission Rate (tons/yr)	Maximum Annual Emission Rate (tons/yr)	Significant?
CO	100	414	Yes
NO_X	40	369	Yes
SO_2	40	70	Yes
PM	25	447	Yes
PM_{10}	15	445	Yes
O_3	40 (of VOC)	173 (of VOC)	Yes
H_2SO_4 Mist	7	24	Yes

H_2SO_4 = sulfuric acid.

Table G-4 summarizes the results of the BACT analysis. The detailed BACT analysis is presented in Attachment E.

Table G-4
BACT Summary

Air Pollutant	BACT	Emission Limit
NO_X	DLN, SCR	2.5 ppmvd, corrected to 15 percent O_2, based on 24-hour average
CO	Good combustion, oxidation catalyst	4.7 ppmvd, corrected to 15 percent O_2, based on 8-hour rolling average
VOC	Good combustion, oxidation catalyst	3.5 ppmvd, corrected to 15 percent O_2, based on 24-hour average
SO_2	Pipeline-quality natural gas	4.01 lb/hr per CGT + HRSG, based on 24-hour average
PM	Pipeline-quality natural gas	25.5 lb/hr per CGT + HRSG, based on 24-hour average
PM_{10}	Pipeline-quality natural gas	25.4 lb/hr per CGT + HRSG, based on 24-hour average
H_2SO_4 mist	Pipeline-quality natural gas	1.36 lb/hr per CGT + HRSG, based on 24-hour average
NH_3	SCR	10 ppmvd, corrected to 15 percent O_2, based on 24-hour average or 31.1 lb/hr per CGT + HRSG, based on 24-hour average

DLN = dry, low-NO_x.
NH_3 = ammonia.

G.3 Air Quality Impact Analysis

The generation plant site will be in southeastern Washington in an area characterized by complex terrain.

Under 173-460 WAC, a new source must evaluate emissions of TAPs and evaluate the impact on ambient air quality of the proposed facility. To demonstrate the methods used in analyzing ambient air quality impacts for the generation plant, a modeling protocol, dated March 26, 2001, was prepared. Written comments were received from Ecology by e-mail on March 30, 2001. Those comments have been incorporated into this analysis. The protocol is presented in Attachment B and is referenced throughout this section. This section presents the source information followed by the necessary modeling information and the modeling results. The building dimension information discussed briefly in Section G.3.1 is presented in detail in Attachment C. Class II modeling is discussed in Section G.3.3. Class II modeling files and other information included in Attachment D are available electronically upon request. Section G.3.4 discusses the Class I modeling that was performed. Class I modeling files included in Attachment H are available electronically upon request.

The air quality analysis for the generation plant site evaluated a combination of operating scenarios. Turbine performance and emissions will be affected by ambient temperature and operating load. In addition, the generation plant will use duct firing, evaporating cooling, and steam injection to enhance turbine performance during certain conditions.

To characterize the impact from the possible combinations of operating scenarios, 13 scenarios have been modeled. These represent conditions that might occur for a worst-case 24-hour period, but realistically cannot occur at all times during the year. However, to bracket the possible combinations of modeled impacts, all modeling has conservatively assumed each of the 13 scenarios could be in operation for an entire year.

G.3.1 GEP/Stack Characteristics

In addition to emission rates, the modeling analysis requires estimates of stack heights, building dimensions, and other exit parameters that characterize exhaust flow from the combustion turbine stacks. These release parameters have an important influence on the results of the analysis. A combination of the stack parameters shown in Table G-5 was used. These parameters were for the 13 scenarios described previously (see Attachment I). The combustion turbines are likely to operate in a range of loading scenarios and temperatures. The maximum, average, and minimum ambient temperatures for each scenario are presented. A range of loading scenarios and ambient temperatures must be considered because the plume rise and plume buoyancy are sensitive to changes in stack parameters.

A good engineering practice (GEP) stack height design analysis is based on EPA procedures (EPA, 1985) and the latest design specifications for the generation plant. Releases below the GEP stack height potentially are subject to building wake effects. For the purposes of PSD review, EPA does not allow credit for the added dispersion associated with releases above the GEP stack height and restricts the simulated heights in the modeling to the GEP stack height.

EPA’s Building Profile Input Program (BPIP, version 95086) was used for the GEP analysis. The generation plant site plan displays the locations of the stacks and buildings onsite. BPIP assesses the area of influence for each structure based on the wind direction, building height, and projected building width.

The results of the BPIP calculations indicate that the GEP stack height for the units will be 300 feet. The combustion turbine building blocks, the air-cooled condenser, and the HRSGs will most affect plume rise from the turbine units.

G.3.2 Existing Ambient Air Quality Including Meteorology

G.3.2.1 Background Ambient Air Quality Information

Background concentrations for the analysis were obtained from the EPA's Aerometric Information Retrieval System (AIRS). The pollutant monitoring stations nearest to the generation plant were used to represent the conditions there. A summary of the data for the past 5 years was reviewed. This is an electronic database available via the EPA Web site (www.epa.gov/airsdata), that provides pollutant monitoring data through December 2000. The summary of this information included in Attachment D is available electronically upon request.

The closest ambient pollutant monitoring sites are for PM_{10}. The nearest PM_{10} monitoring station is located in Walla Walla, Washington. Data were available for the last 5 years at the site for annual PM_{10} and 24-hour PM_{10}. The highest 24-hour concentration of 114 micrograms per cubic meter ($\mu g/m^3$) occurred at the Walla Walla site in 1997. The maximum annual mean PM_{10} concentration was 28.8 $\mu g/m^3$ and it occurred at the Walla Walla site in 1997.

There are no NO_X monitoring sites in eastern Washington. In 1983, Pratt and others recorded average background concentrations of 0.1 to 7.2 ppm (0.16 to 11 $\mu g/m^3$) in rural parts of the United States (Smith, 1990). In the absence of other data, 11 $\mu g/m^3$ was used as the background NO_X concentration. This value was used in the modeling for the Northwest Regional Power Facility in Creston, Washington (1993).

No other background concentrations were used in the analysis.

G.3.2.2 Meteorology

A meteorological monitoring station was installed at the generation plant site in December 2000 to collect data suitable for use in an atmospheric dispersion modeling analysis. The parameters being measured include wind speed, wind direction, and temperature. The sensors are mounted on a 10-meter-tall tower designed to meet the requirements for collecting onsite data for permitting and modeling under EPA's PSD regulations. Monitoring requirements under PSD are defined in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-07) and *Quality Assurance Handbook for Air Pollution Measurement Systems Volume IV - Meteorological Measurements* (EPA/600/R-94/038d-April 1994).

Details of the meteorological station, the monitoring program, and data reduction are included in Attachment A.

G.3.3 Class II Dispersion Modeling

The Class II dispersion modeling analysis was conducted in accordance with the air dispersion modeling protocol developed for the generation plant. The protocol was submitted to Mr. Clint Bowman of Ecology and Mr. Bob Bachman of the USDA Forest Service (USFS) on March 27, 2001. Comments were received from Clint Bowman on March 30, 2001, and from Bob Bachman on April 18, 2001. The protocol and the comments are included in Attachment B.

G.3.3.1 Source Information

In this analysis, combinations of load factors and ambient temperature were evaluated. Load conditions of 70 percent, 85 percent, and 100 percent, with and without duct burning, were analyzed at each of three ambient temperatures: -20°F, 51.1°F, and 101°F. In addition, one average ambient temperature scenario with 100 percent loading and duct firing also was modeled with steam injection. The 100 percent loading scenario without duct firing at maximum ambient temperature included evaporative cooling. The 100 percent loading scenario without duct firing at maximum ambient temperature included both evaporative cooling and steam injection. Even though these conditions can occur only during certain periods of the year, all of these cases were evaluated and the maximum impacts reported. Complete emissions information for these conditions is in Section G.3.3.3.

Table G-5 summarizes the standard stack information for the generation plant sources. The stack exhaust temperatures and exit velocity vary by both operating parameter and ambient temperature. Exhaust temperature and velocity information are included in Section G.3.3.3, Table G-12.

TABLE G-5
Stack Parameters for Sources Modeled

Stack Name	UTM East (m)	UTM North (m)	Elevation (m)	Stack Height m(ft)	Diameter m(ft)
CT Block 1	407,833	5,158,422	216	53.3 (175)	5.79 (19)
CT Block 2	407,870	5,158,422	216	53.3 (175)	5.79 (19)
Fire Pump	407,831	5,158,378	216	10.7 (35)	0.25 (0.83)

The generation plant will be a complex industrial source with numerous buildings and stacks. For this reason, the effect of building downwash was considered. Detailed building dimension information is included in Attachment C. The direction-specific building downwash parameters used in ISCST3 were calculated using EPA's BPIP (Version 95806). Copies of the BPIP input and output files included in Attachment D are available electronically upon request.

G.3.3.2 Modeling Summary

Modeling Options

For the Class II air quality analysis, the EPA-approved ISCST3 (Version 00101) model was run with the following options:

- Regulatory defaults

- Direction-specific building downwash
- 30-meter anemometer height
- Actual receptor elevations
- Complex and intermediate terrain algorithms (if appropriate)

Rural/Urban

Auer's (1978) land-use classification method was used to determine the dispersion mode for the analysis. Because more than 50 percent of the land use within 3 kilometers around the generation plant appears to be rural, the model was run using the rural dispersion coefficients.

Meteorology

A monitoring station has been installed at the generation plant site and is collecting data. Modeling was conducted using data from January 20, 2001, through July 5, 2001, the first 6 months of data collected; the impacts will be reevaluated upon collection of 1 year's worth of data. The surface data were processed with upper air data collected at the Spokane, Washington, airport monitoring station.

There were 24 hours of missing data in this period. The missing data hours were due to periodic preventive maintenance and quality assurance procedures. Details about the meteorological monitoring program are presented in Attachment A.

Figure G-2 shows the annual windrose of the meteorological data set used in the analysis.

Receptors

The ISCST3 model was run first with a nested Cartesian grid of 50-meter-spaced receptors within a 100-meter grid. The 50-meter grid extended about 3 kilometers around the generation plant site, while the 500-meter grid extended about 5 kilometers. In addition, receptors were placed at 50-meter intervals around the property boundary. Receptor elevations were extracted from U.S. Geological Survey (USGS) Digital Elevation Model (DEM) files.

Evaluation of Project Impacts

The dispersion modeling analysis for a PSD permit application generally involves two phases: (1) a preliminary analysis and (2) a full impact analysis. The preliminary analysis models only the relevant increase from the proposed new source itself. The full impact analysis expands the preliminary analysis to consider emissions from the proposed source, existing sources in the area, secondary emissions, and consideration of background concentrations. For SO_2, PM_{10}, and NO_x, the full impact analysis consists of separate analyses for the NAAQS and PSD increments. There is no PSD increment for CO. A full impact analysis is not required, however, if the results of the preliminary analysis show that emissions of a particular pollutant from the proposed source would not increase ambient concentrations by more than prescribed screening levels, called significant impact levels (SILs). These levels are identified in 40 CFR 51.165(b)(2) and in EPA modeling guidance.

Because there is only one source within approximately 31 miles (50 kilometers) of the site, this source was included in the preliminary impact analysis. Modeled impacts were compared to the SILs and the corresponding ambient air quality standards and PSD increments.

The only permitted source located within 31 miles (50 kilometers) of the generation plant is the Pacific Gas Transmission-Northwest Compressor Station 7, which is located 5 miles (8.2 kilometers) to the southwest of the generation plant. Table G-6 includes source parameter information for this source and Table G-7 presents the emissions. This information was obtained from Ecology. Discussion of background concentrations is included in Section G.3.2.1. Table G-8 contains a summary of the preliminary analysis results showing the maximum impacts per pollutant by averaging period for the emissions from the generation plant and Pacific Gas Transmission Northwest Compressor Station 7. Figure G-3 shows the maximum impact locations by pollutant and averaging period. Attachment D presents the maximum impact by pollutant, by averaging period, and operating scenario. As shown in Table G-8, the ambient impacts for all pollutants, except for annual and 24-hour PM_{10} and annual NO_X, are less than the SILs. Further analysis is required for only these pollutants.

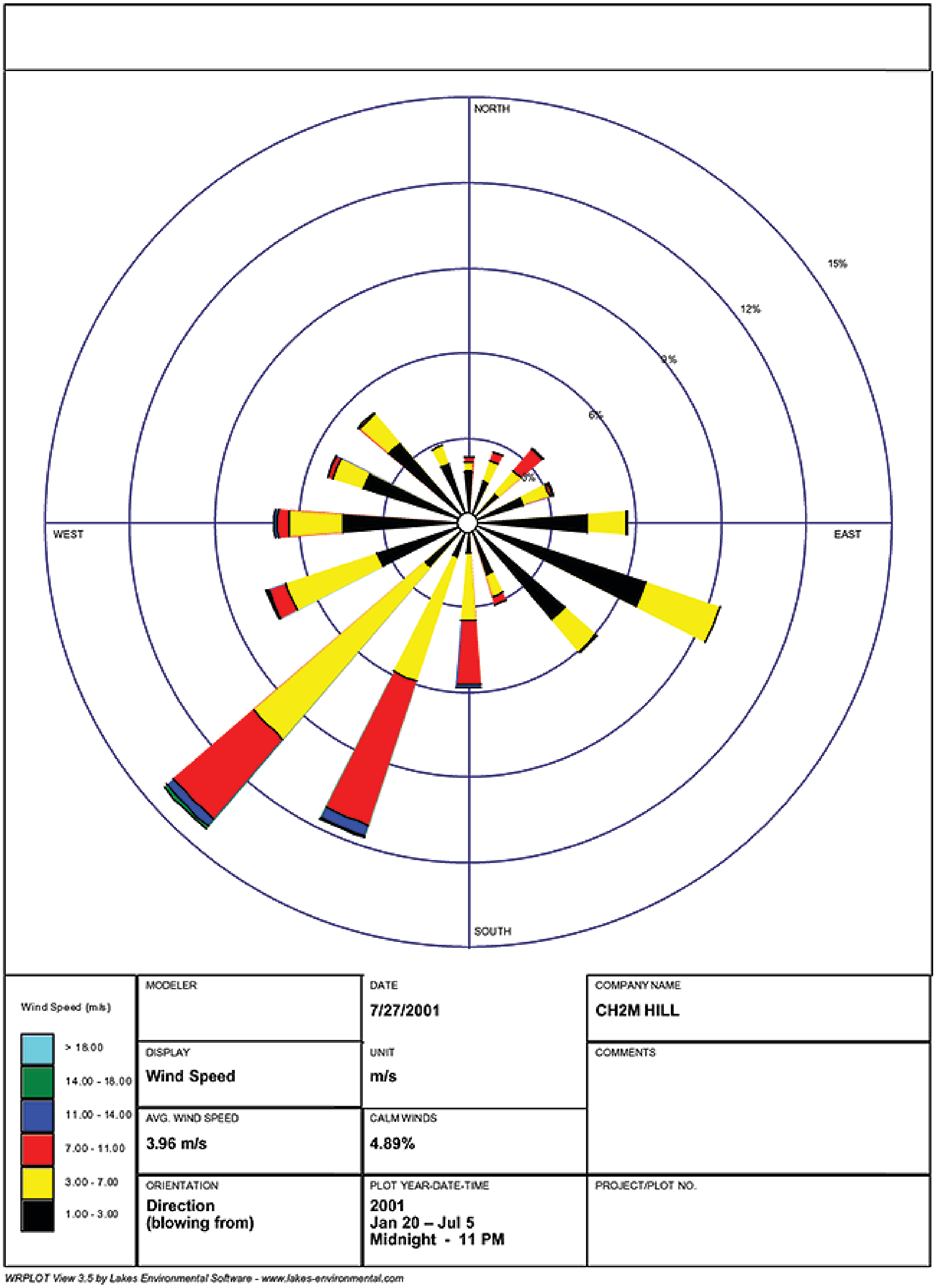
Table G-6
Competing Source Modeling Information

Source	UTM East (meters)	UTM North (meters)	Elevation (meters)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (meters/ second)	Stack Diameter (meters)
Pacific Gas Transmission Northwest - Unit B	400,801	5,154,179	329	9.4	866	56.5	2.13
Pacific Gas Transmission Northwest - Unit C	400,722	5,154,166	325	12.76	726	25.7	2.94

Table G-7
Competing Source Emission Rates

	Annual PM_{10} (g/s)	24 Hour PM_{10} (g/s)	Annual NO_x (g/s)
Pacific Gas Transmission Northwest - Unit B	0.095	0.095	5.41
Pacific Gas Transmission Northwest - Unit C	0.16	0.16	5.90

The minor source baseline for TSP was 1977.
g/s = grams per second.



Wind Speed (m/s)

- 🟦 > 18.00
- 🟩 14.00 - 18.00
- 🟦 11.00 - 14.00
- 🟥 7.00 - 11.00
- 🟨 3.00 - 7.00
- ⬛ 1.00 - 3.00

MODELER

DATE
7/27/2001

COMPANY NAME
CH2M HILL

DISPLAY
Wind Speed

UNIT
m/s

COMMENTS

AVG. WIND SPEED
3.96 m/s

CALM WINDS
4.89%

ORIENTATION
Direction
(blowing from)

PLOT YEAR-DATE-TIME
2001
Jan 20 – Jul 5
Midnight - 11 PM

PROJECT/PLOT NO.

WRPLOT View 3.5 by Lakes Environmental Software - www.lakes-environmental.com

FIGURE G-2
Wind Speed and Direction at the Generation Plant Site
Application for Site Certification
STARBUCK POWER PROJECT
STARBUCK, WASHINGTON

TABLE G-8
Results from Initial Analysis for Criteria Pollutants

Pollutant	Averaging Period	Maximum Predicted Concentration (μg/m^3)	Significant Impact Level (μg/m^3)	Receptor Location X (UTM) (meters)	Receptor Location Y (UTM) (meters)	Receptor Elevation (meters)	Percent Operating Scenario	Scenario No.
NO_X	Annual	1.8	1	405,450	5,159,550	376	100	4
CO	1-Hour	129.8	2,000	407,950	5,156,700	396	100	6
CO	8-Hour	31.6	500	407,550	5,156,450	359	100	4
SO_2	3-Hour	9.3	25	408,000	5,156,700	396	100	4
SO_2	24-Hour	1.9	5	407,950	5,156,700	396	100	6
SO_2	Annual	0.3	1	405,450	5,159,550	376	100	4
PM_{10}	24-Hour	13.5	5	407,950	5,156,750	389	100	4
PM_{10}	Annual	2.1	1	405,450	5,159,550	376	100	4

UTM = Universal transverse mercator.

Full Impacts Analysis

The full impacts analysis for annual and 24-hour PM_{10} and annual NO_x concentrations involved a comparison of generation plant impacts to ambient air quality standards and applicable PSD increments. This included a competing source analysis and consideration of background concentrations.

Table G-9 summarizes the results of the analysis of impacts against ambient air quality standards for annual and 24-hour PM_{10} and annual NO_x. The maximum modeled annual PM_{10} concentration was 2.1 μg/m^3. When added to the background concentration of 28.8 μg/m^3, impacts remain below the ambient air quality standard of 50 μg/m^3. The maximum modeled 24-hour PM_{10} concentration was 13.5 μg/m^3. When this number is added to the 24-hour background concentration of 114 μg/m^3, impacts remain below the ambient air quality standard of 150 μg/m^3. The maximum modeled annual NO_x concentration was 1.8 μg/m^3. When this number is added to the annual background of 11 μg/m^3, impacts remain well below the ambient air quality standard of 100 μg/m^3. Figure G-3 shows the maximum impact location for the ambient air quality standards analysis.

The generation plant will emit precursors to ozone, including VOCs and NO_X. Ozone is formed through a photochemical reaction between VOCs and NO_x. Areas with high ozone concentrations are typically downwind of large urban areas, which have significant emissions of these precursor compounds. Emissions of these compounds are primarily from transportation and other urban sources.

There are no ozone non-attainment or maintenance areas in eastern Washington or Idaho. Ozone is not typically evaluated from single sources because ozone models are regional-scale grid models and it is not possible to use them for single-source evaluations. However, because of the remote location of this source and the lack of areas with high ozone concentrations within several hundred miles, ozone impacts from this source will be insignificant.

TABLE G-9
Analysis of Impacts Against Ambient Air Quality Standards

Averaging Period	Maximum Impact ($\mu g/m^3$)	Coordinates (UTM; meters) and Elevation (meters)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Primary Ambient Air Quality Standards ($\mu g/m^3$)	Secondary Ambient Air quality Standards ($\mu g/m^3$)
Annual PM_{10}	2.1	(405,450; 5,159,550) (376)	28.8	30.9	50	50
24-Hour PM_{10}	13.5	(407,950; 5,156,750) (389)	114	127.5	150	150
Annual NO_X	1.8	(405,450; 5,159,550) (376)	11	12.8	100	100

Compliance with Class II PSD Increment

The PSD increment consumption for receptors above the SIL was evaluated. This evaluation included increment consuming sources from all nearby sources with emissions increases since baseline. Information about increment consumption was obtained from Ecology.

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

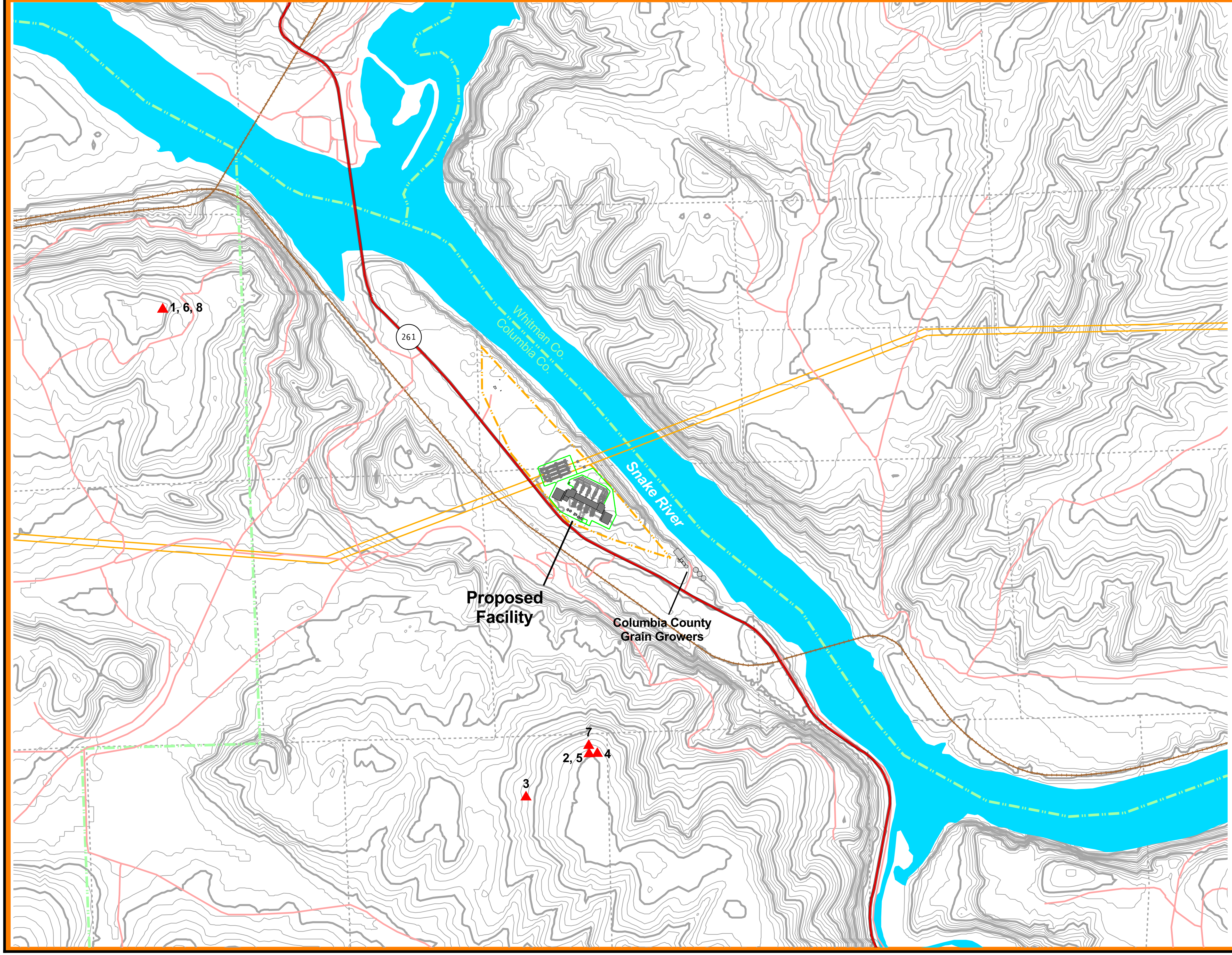
Table G-7 summarizes the emissions from the PM_{10} and NO_X PSD increment consuming sources included in the modeling analysis. Table G-10 presents the results of the Class II PSD increment analysis. The annual PM_{10} impact of 2.1 $\mu g/m^3$ is below the allowable Class II PSD increment of 17 $\mu g/m^3$. The 24-hour PM_{10} impact of 13.5 $\mu g/m^3$ is below the allowable Class II PSD increment of 30 $\mu g/m^3$. The annual NO_X impact of 1.8 $\mu g/m^3$ is below the allowable Class II PSD increment of 25 $\mu g/m^3$. Figure G-3 shows the maximum impact location for the PSD increment.

TABLE G-10
Class II PSD Increment Analysis Results

Averaging Period	Maximum Concentration ($\mu g/m^3$)	Coordinates (UTM; m) and Elevation (m)	Allowable Class II PSD Increases ($\mu g/m^3$)
Annual PM_{10}	2.1	(405,450; 5,159,550) (376)	17
24-Hour PM_{10}	13.5	(407,950; 5,156,750) (389)	30
Annual NO_x	1.8	(405,450; 5,159,550) (376)	25

Figure G-3
Class II
Modeling Results

Application for
Site Certification
Starbuck Power Project
Starbuck, Washington



N

2000 0 2000 Feet

Legend

▲ Modeling Results

1 NOx - Annual
2 CO - 1 Hour
3 CO - 8 Hour
4 SO2 - 3 Hour
5 SO2 - 24 Hour
6 SO2 - Annual
7 PM10 - 24 Hour
8 PM10 - Annual

Proposed Site Property

Transmission Lines

State Routes (SR)

Secondary Roads

Railroads

County Boundary

Elevation Contours - 20 Ft

Elevation Contours - 100 Ft

CH2M Hill GIS Project Number 155676 \\Starbuck\Aprs\facility.apr 8-7-2001

CH2MHILL

Toxic Dispersion Modeling

173-460 WAC requires evaluation of listed TAPs to demonstrate compliance with the ASILs. A preliminary analysis was conducted in which the estimated quantity of the listed TAPs from the generation plant was compared to the small quantity emission rates (SQER) specified in the regulation. Those pollutants whose emissions were predicted to exceed the SQER were modeled and their concentrations compared to the ASIL.

Table G-11 summarizes the modeling results for the TAPs that exceeded the SQER. All the input and output files used in this section that are included in Attachment D are available electronically upon request.

TABLE G-11
Results from Fine Grid Analysis for Toxic Pollutants *

Pollutant	Averaging Period	Maximum Predicted Concentration (µg/m³)	Acceptable Source Impact Level (µg/m³)	Receptor Location X (UTM) (meters)	Receptor Location Y (UTM) (meters)	Receptor Elevation (meters)	Percent Operating Scenario
Acetaldehyde	Annual	0.02884	0.45	405,450	5,159,550	376	100
PAH	Annual	0.00037	0.00048	405,450	5,159,550	376	100
Benzene	Annual	0.00058	0.12	405,450	5,159,550	376	100
Formaldehyde	Annual	0.06077	0.077	405,450	5,159,550	376	100
Acrolein	24 Hour	0.00382	0.02	407,950	5,156,750	389	100
Sulfuric Acid Mist	24 Hour	0.69044	3.3	407,950	5,156,750	389	100
Ammonia	24 Hour	15.78855	100	407,950	5,156,750	389	100

PAH = polycyclic aromatic hydrocarbons.
* Toxic dispersion modeling analysis for acetaldehyde, PAH, benzene, formaldehyde, and acrolein will be revised based on the revised emission rates provided in Table G-19. The revised emission rates for acetaldehyde, PAH, formaldehyde, and acrolein are lower, whereas the revised emission rate for benzene is higher.

G.3.3.3 Emissions Information

Criteria Pollutant Emissions

Combustion turbines and duct burners associated with the HRSGs at the generation plant will use natural gas as the only fuel. Combustion of natural gas results in emissions of PM, PM_{10}, NO_X, SO_2, CO, and VOCs.

The generation plant is expected to include four Siemens Westinghouse Power Corporation (SWPC) 501F combustion turbines or equivalent, four HRSGs equipped with supplemental duct firing, and other equipment. Supplemental duct firing with low NO_X burners will be used for additional peaking demand, particularly during the summer months.

Combustion turbines and duct burners associated with the HRSGs will be equipped with dry, low-NO_X (DLN) burners. In addition, the generation plant will use steam injection on a periodic basis for power augmentation, which would be an additional technique for controlling NO_X emissions from the combustion turbines. The NO_X emissions from the combustion turbines and duct burners associated with HRSGs will be further controlled using SCR. However, use of SCR will result in ammonia (NH_3) emissions, which are commonly referred to as ammonia slip. Release of NH_3 also results in emissions of additional PM in the form of ammonium bisulfate [$2(NH_4(SO_4))$].

CO emissions from the combustion turbines and duct burners associated with HRSGs will be controlled using an oxidation catalyst. Use of the oxidation catalyst for controlling CO emissions will also result in control of VOC emissions. Use of an oxidation catalyst may result in oxidation of some of the SO_2 to sulfur trioxide, which combines with water to form sulfuric acid (H_2SO_4) mist. Use of an oxidation catalyst also increases the conversion of nitric oxide to nitrogen dioxide, which will result in increased ammonia consumption and subsequently higher ammonia emissions.

Table G-12 summarizes combustion characteristics and emissions of criteria pollutants from the combustion turbines and duct burners associated with the HRSGs under different operating conditions. Table G-12 identifies a total of 13 operating scenarios.

Maximum emissions of PM_{10}, NO_X, SO_2, CO, and VOCs have been projected to occur when the combustion turbines are operated at 100 percent load at the minimum ambient temperature condition of -20°F, the duct burning in the HRSGs is on, the evaporative cooling is off, and there is no steam injection. Maximum emissions of PM have been projected to occur when the combustion turbines are operated at 100 percent load at the average ambient temperature condition of 51.1°F, the duct burning in the HRSGs is on, the evaporative cooling is off, and there is no steam injection.

Table G-12 also provides details of projected emission rates for NH_3, H_2SO_4 mist, unburned hydrocarbons (UHC), and PM in the form of $2(NH_4(SO_4))$.

The combustion turbines and the HRSGs will not be operated under one particular operating scenario at all times during the year. To be conservative, the proposed annual emission rates of the various criteria pollutants are based on the maximum short-term emission rates under various operating scenarios times 8,760 hours of operation per year.

In addition, combustion of diesel fuel in the fire pump also results in emissions of PM, PM_{10}, NO_X, SO_2, CO, and VOCs. The maximum hours of operation for the diesel fire pump are 1 hour per day, with an annual limit of 10 hours per year. Table G-13 summarizes the combustion characteristics and emissions of criteria pollutants from combustion of diesel fuel in the fire pump.

Table G-14 summarizes the maximum annual emission rates of regulated pollutants, including the criteria pollutants and NH_3, H_2SO_4 mist, UHC, and $2(NH_4(SO_4))$ from the combustion turbines, HRSGs, and the fire pump.

TABLE G-12
Combustion Characteristics and Criteria Pollutant Emissions from Combustion Turbines and Heat Recovery Steam Generators

	Scenario												
	1	2	3	4	5	6	7	8	9	10	11	12	13
Parameter	**Operating Condition**												
HRSG Duct Firing	Fired Natural Gas	Unfired	Fired Natural Gas	Fired Natural Gas	Unfired	Fired Natural Gas	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Ambient Temperature (°F)	101	101	51.1	51.1	51.1	-20	-20	-20	-20	51.1	51.1	101	101
Evaporative Cooling Included	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No
Steam Injection Included	Yes	No	Yes	No	No	No	No	No	No	No	No	No	No
CGT Load Level (percent of base load)	100%	100%	100%	100%	100%	100%	100%	85%	70%	85%	70%	85%	70%
Stack Exit Temperature (°F)	227	227	221	211	214	228	227	227	227	227	227	227	227
Stack Diameter (ft)	19	19	19	19	19	19	19	19	19	19	19	19	19
Stack Height (ft)	175	175	175	175	175	175	175	175	175	175	175	175	175
Stack Exit Velocity (ft/sec)	64.4	60.7	67.1	62.7	62.6	70.4	69.9	65.4	57.8	59.8	52.9	54.4	49.3
Pollutant	**Emission Rate**												
NO_X (lb/hr as NO_2 with SCR)	19.1	15.7	19.8	19.0	16.6	21.0	18.6	16.4	14.1	14.5	12.5	12.6	11.1
NH_3 slip (lb/hr with SCR)	28.3	23.2	29.4	28.2	24.5	31.1	27.5	24.3	20.8	21.4	18.5	18.7	16.5
CO (lb/hr with catalyst)	21.3	15.2	21.9	21.7	16.1	23.6	18.1	16.0	13.7	14.1	12.2	12.3	10.8
H_2SO_4 mist (lb/hr)	1.18	1.05	1.24	1.23	1.12	1.36	1.25	1.12	0.97	0.99	0.86	0.87	0.77
SO_2 (lb/hr)	3.68	2.96	3.81	3.63	3.13	4.01	3.51	3.09	2.64	2.72	2.34	2.38	2.09
UHC (lb/hr as CH_4)	25.8	10.5	25.7	27.7	11.1	28.8	12.4	11.0	9.4	9.7	8.3	8.5	7.4
VOC (lb/hr as CH_4)	8.9	2.6	8.5	9.4	2.8	9.9	3.1	2.7	2.4	2.4	2.1	2.1	1.9
PM (lb/hr) [front and back excluding $2(NH_4(SO_4))$]	24.8	20.0	24.6	25.5	20.0	25.4	20.0	20.0	20.0	20.0	20.0	20.0	20.0
PM_{10} (lb/hr) [front and back excluding $2(NH_4(SO_4))$]	24.8	20.0	23.7	24.4	20.0	25.4	20.0	20.0	20.0	20.0	20.0	20.0	20.0
$2(NH_4(SO_4))$ (lb/hr)	1.58	1.41	1.67	1.66	1.50	1.84	1.69	1.51	1.30	1.34	1.16	1.18	1.04

CH_4 = methane

TABLE G-13
Combustion Characteristics and Criteria Pollutant Emissions from Diesel-Fuel-Fired Fire Pump

Parameter	Value
Fire Pump Stack Temperature	840 °F
Fire Pump Stack Height [b]	35 ft
Fire Pump Stack Diameter [a]	0.83 ft
Fire Pump Stack Exhaust Flow Rate	1,404 acfm
Fire Pump Stack Exit Velocity	42.90 ft/sec
NO_x Emission Rate (as NO_2)	3.91 lb/hr
CO Emission Rate	0.17 lb/hr
SO_x Emission Rate (as SO_2) [d]	0.10 lb/hr
PM_{10} Emission Rate	0.04 lb/hr
PM Emission Rate	0.04 lb/hr
VOC Emission Rate [c]	0.13 lb/hr
UHC Emission Rate	0.13 lb/hr

Notes:
[a] Fire pump stack diameter is assumed to be 10 inches.
[b] Fire pump stack height is assumed to be 35 feet.
[c] VOC emission rate is assumed to be the same as UHC emission rate.
[d] Based on maximum fuel flow rate of 14.2 gal/hr, density of 7.1 lb/gal for diesel, 0.05% sulfur content in diesel, and conversion of all sulfur to SO_2.
acfm = actual cubic feet per minute.

TABLE G-14
Maximum Short-Term and Annual Criteria Pollutant Emission Rates

Pollutant	Maximum Short-Term Emission Rate from Fire Pump (lb/hr)	Maximum Short-Term Emission Rate Per Combustion Turbine and HRSG (lb/hr)	Maximum Annual Emission Rate for All Four Combustion Turbines and HRSGs and Fire Pump (tons/yr)
NO_X (as NO_2)	3.91	21.0	368
NH_3	NA	31.1	545
CO	0.17	23.6	413
H_2SO_4 mist	NA	1.36	24
SO_2	0.10	4.01	70
UHC	0.13	28.8	505
VOC	0.13	9.9	173
PM [excluding $2(NH_4(SO_4))$]	0.04	25.5	447
PM_{10} [excluding $2(NH_4(SO_4))$]	0.04	25.4	445
$2(NH_4(SO_4))$	NA	1.84	32

Table G-15 compares the significant emission rates provided in 40 CFR Part 52.21(b)(23)(i) and the combined maximum annual emission rates for all four combustion turbines and HRSGs and the fire pump. As shown in Table G-15, the maximum annual emission rates for CO, NO_X, SO_2, PM, PM_{10}, ozone (as VOC), and H_2SO_4 mist exceed the significant emission rate thresholds provided in the PSD regulations. Consequently, these pollutants are subject to PSD review, which requires a BACT analysis and an air quality impact analysis for those pollutants with an ambient air quality standard. A BACT analysis has been completed and is included as Attachment E.

TABLE G-15
Comparison of Maximum Annual Criteria Pollutant Emissions with Significant Emission Rates

Pollutant	Significant Emission Rate (tons/yr)	Maximum Annual Emission Rate (tons/yr)	Significant?
CO	100	414	Yes
NO_X	40	369	Yes
SO_2	40	70	Yes
PM	25	447	Yes
PM_{10}	15	445	Yes
O_3	40 (of VOC)	173 (of VOC)	Yes
H_2SO_4 Mist	7	24	Yes

Toxic Air Pollutant and Hazardous Air Pollutant Emissions

The generation plant has the potential to emit small quantities of TAPs and HAPs that are regulated by Ecology. Some of the TAPs also are included in the list of HAPs that are regulated under the CAA. Available data indicate that the emission levels of HAPs are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operations. Benzene, toluene, xylenes, polycyclic aromatic hydrocarbons (PAH), formaldehyde, and other organic compounds associated with the combustion of natural gas will be released into the atmosphere from the stacks associated with combustion turbines. Formation of CO during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions will increase with reduced operating loads. In addition, use of SCR as the BACT for controlling NO_X emissions from combustion turbines and duct burners will result in ammonia emissions; this is commonly referred to as ammonia slip. The use of an oxidation catalyst for controlling CO emissions will result in oxidation of some of the SO_2 to sulfur trioxide, which combines with water to form H_2SO_4 mist. However, using an oxidation catalyst will also result in oxidation of some of the TAPs and HAPs that are formed as a result of natural gas combustion in the CGTs and duct burners associated with the HRSGs. Detailed information about the emissions of various TAPs and HAPs resulting from combustion of natural gas in the combustion turbines and duct burners at the generation plant, and the use of ammonia in the SCR process, is provided in this section.

HAP emissions from natural gas-fired stationary gas turbines at the generation plant are based on the emission factors provided in Table 3.1-3 of EPA Document AP-42. These emission factors are based on information provided in a support document titled *Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines*, prepared by Alpha-Gamma Technologies, Inc., dated April 2000. The emission factors provided in Table 3.1-3 of EPA Document AP-42 are uncontrolled emission factors and do not take into account the use of any control technology. As stated earlier, a CO catalyst will be used to control CO emissions. Using a CO catalyst will also result in oxidation of HAPs produced during natural gas combustion in the combustion turbines. A memorandum dated August 21, 2001, from Mr. Sims Roy of EPA's Office of Air Quality Planning and Standards, states that "the performance of these oxidation catalyst systems on diffusion flame combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are also achieved on other HAP pollutants." HAP emissions from combustion turbines at the generation plant have been estimated based on 85 percent control of formaldehyde emissions and a 50 percent control efficiency for other pollutants. The summary of HAP emission factors for combustion turbines, based on either no controls or the use of CO catalyst at all load conditions, is provided in Table G-16. Emission factors have been provided only for those HAPs for which the emission factor is not preceded by a "less than" sign.

TABLE G-16
HAP Emission Factors for Natural-Gas-Fired Turbines

Pollutant	Uncontrolled Emission Factor (lb/MMBtu)	Controlled Emission Factor (lb/MMBtu) *
Acetaldehyde	4.0 E-05	2.0 E-05
Acrolein	6.4 E-06	3.2 E-06
Benzene	1.2 E-05	6.0 E-06
Ethylbenzene	3.2 E-05	1.6 E-05
Formaldehyde	7.1 E-04	1.065 E-04
Naphthalene	1.3 E-06	6.5 E-07
PAH	2.2 E-06	1.1 E-06
Toluene	1.3 E-04	6.5 E-05
Xylenes	6.4 E-05	3.2 E-05

* Controlled emission factor for formaldehyde is based on an 85 percent control efficiency, whereas the controlled emission factors for other HAPs are based on 50 percent control efficiency.

HAPs also are emitted as a result of the combustion of natural gas in the duct burners associated with HRSGs. Table 1.4-3 in EPA Document AP-42 provides the emission factors for speciated organic compounds from natural gas combustion in the boilers, which also includes the emission factors for various HAPs. The emission factors provided in Table 1.4-3 of EPA Document AP-42 do not take into consideration the control efficiency resulting from the use of CO catalyst for control of CO emissions, which also results in oxidation of various HAPs. Similar to the assumptions used for estimating controlled HAP emissions from combustion turbines, the HAP emissions from duct burners associated with HRSGs have been estimated based on 85 percent control of formaldehyde emissions and a 50 percent control efficiency for other pollutants. The summary of uncontrolled and controlled HAP emission factors for natural gas combustion in the duct burners associated with HRSGs is provided in Table G-17. Emission factors have been provided only for those HAPs for which the emission factor is not preceded by a "less than" sign.

TABLE G-17
HAP Emission Factors for Natural-Gas-Fired Boilers

Pollutant	Uncontrolled Emission Factor ($lb/10^6$ scf)	Controlled Emission Factor ($lb/10^6$ scf) [b]
2-Methylnaphthalene *	2.4 E-05	1.2 E-05
Benzene	2.1 E-03	1.05 E-03
Dichlorobenzene	1.2 E-03	6.0 E-04
Fluoranthene *	3.0 E-06	1.5 E-06
Fluorene *	2.8 E-06	1.4 E-06
Formaldehyde	7.5 E-02	1.125 E-02
Hexane	1.8 E+00	9.0 E-01
Naphthalene	6.1 E-04	3.05 E-04
Phenanathrene *	1.7 E-05	8.5 E-06
Pyrene *	5.0 E-06	2.5 E-06
Toluene	3.4 E-03	1.7 E-03
PAH [a]	5.18 E-05	2.59 E-05

[a] The emission factor for PAH is the sum of the emission factors for various HAPs marked with an asterisk (*).
[b] Controlled emission factor for formaldehyde is based on an 85 percent control efficiency, whereas the controlled emission factors for other HAPs are based on 50 percent control efficiency.
scf = standard cubic feet.

HAPs also are emitted from the combustion of diesel fuel in the fire pump. Table 3.3-2 in EPA Document AP-42 provides the emission factors for speciated organic compounds from diesel fuel combustion in uncontrolled diesel industrial engines, which also includes the emission factors for various HAPs. Table G-18 provides a summary of HAP emission factors for diesel fuel combustion in the fire pump. Emission factors have been provided only for those HAPs for which the emission factor is not preceded by a "less than" sign.

The heat input rates for the combustion turbines and duct burners associated with HRSGs will vary depending on which scenario (combination of CGT load level, ambient temperature, evaporative cooling status, steam injection status, and duct burning status) the generation plant is operating. However, the TAP and HAP emissions calculations for the combustion turbines and duct burners associated with HRSGs are based on the assumption that the maximum heat input rate for each of the combustion turbines under any operating scenario is 2,080.28 MMBtu/hr high heat value (HHV) and the maximum heat input rate for each of the duct burners associated with HRSGs under any operating scenario is 275.9 MMBtu/hr (HHV). For converting the HAP emission factors from $lb/10^6$ standard cubic feet (scf) to lb/MMBtu, the heat value of natural gas has been assumed to be 1,020 Btu/scf. The maximum amount of diesel fuel that can be burned in the fire pump is 14.2 gal/hr. Assuming that the heat value of diesel fuel is 140,000 Btu/gal, the maximum heat input rate for the diesel-fuel-fired fire pump is 1.999 MMBtu/hr.

TABLE G-18
HAP Emission Factors for Diesel-Fuel-Fired Fire Pump

Pollutant	Emission Factor (lb/MMBtu)
PAH [a]	1.68 E-04
Anthracene *	1.87 E-06
Benzo(a)anthracene *	1.68 E-06
Benzene	9.33 E-04
Chrysene *	3.53 E-07
Fluoranthene *	7.61 E-06
Fluorene *	2.92 E-05
Formaldehyde	1.18 E-03
Naphthalene	8.48 E-05
Phenanathrene *	2.94 E-05
Pyrene *	4.78 E-06
Toluene	4.09 E-04
Xylenes	2.85 E-04
Acetaldehyde	7.67 E-04

[a] The emission factor for PAH is the sum of the emission factors for various HAPs marked with an asterisk (*).

Table G-19 summarizes TAP and HAP emissions from the combustion turbines and duct burners associated with the HRSGs and the diesel-fuel-fired fire pump.

G.3.4 Class I Dispersion Modeling

G.3.4.1 Introduction

The Class I area impacts modeling analysis was conducted in accordance with the air dispersion modeling protocol developed for the generation plant. The protocol was submitted to Ecology on March 27, 2001. Comments were received from Mr. Clint Bowman of Ecology via e-mail on March 30, 2001. Comments also were received from Mr. Bob Bachman of the U.S. Forest Service via e-mail on April 18, 2001. Both sets of comments were incorporated into the final analysis.

PSD requires evaluation of impacts to Class I areas. The analysis was conducted based on requirements defined in the following documents:

- *Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (IWAQM2) (EPA-454/R-98-019)
- *Federal Land Managers Air Quality Related Values Work Group Phase I Report* (FLAG) (USFS, National Park Service [NPS], U.S. Fish and Wildlife Service [USFWS], 2000)
- *Guidelines on Air Quality Models* (GAQM) (EPA, Appendix W to 40 CFR Part 51)

G.3.4.2 Modeling Methodology

Two kinds of impacts to Class I areas were evaluated—Class I PSD increments and impacts to air quality related values (AQRVs). The AQRV analyses include impacts to visibility and wet and dry deposition.

Class I Areas Evaluated

PSD requires evaluation of impacts to Class I areas. Recent guidance provided by federal land managers and state air agency staff recommends analysis of impacts to all Class I areas up to 125 miles (200 kilometers) from the source. Table G-20 shows the Class I areas within 125 miles (200 kilometers) of the generation plant that were included in the analysis. Because all of the Class I areas are more than 31 miles (50 kilometers) from the source, the analysis applied a non-steady state model with chemical transformation capabilities as recommended in FLAG. As such, the Class I area air quality modeling was performed using the CALMET/CALPUFF modeling system. The analysis followed the guidance provided in IWAQM2 and FLAG. CALMET was used to generate hourly wind flow fields at a 2.4-mile (4-kilometer) resolution. These wind flow fields then were used in the CALPUFF analysis. Chemistry information needed to calculate secondary particle formation and deposition are provided for in the CALPUFF model.

The methodology used for the modeling as well as the approach used to assess each AQRV are described in the following sections.

CALMET Methodology

The CALMET model was run using the following input data:

- Mesocale Model – Generation 5 (MM5) data for the period from April 1, 1998, to February 28, 1999.
- Hourly surface data, for the same period, collected at 12 meteorological monitoring stations in, or near, the CALMET modeling domain (see Figure G-4). The data were archived by the University of Washington Atmospheric Science Department and provided for use in this analysis by Clint Bowman. These stations are:

  John Day State (K5JO)
  Walla Walla (ALW)
  Baker Municipal Airport (KBKE)
  Burns (BNO)
  Spokane International Airport (GEG)
  La Grande (LGD)
  Lewiston Airport (LWS)
  Meacham (KMEH)
  Ontario (ONO)
  Pendleton (PDT)
  Spokane Felts Field (SFF)
  Baker (BKE)

- Pseudo precipitation and upper air data were extracted from the MM5 data for the same period. Precipitation was extracted at every other grid cell and upper air at every fourth grid cell.

TABLE G-19
Summary of TAP and HAP Emissions from Combustion Turbines, Duct Burners Associated with HRSGs, and Diesel-Fuel-Fired Fire Pump

Pollutant	HRSG Controlled Emission Factor (lb/10^6 scf)	Maximum Controlled Short-Term Emission Rate per HRSG (lb/hr)	Combustion Turbine Controlled Emission Factor (lb/MMBtu)	Maximum Short-Term Controlled Emission Rate per Combustion Turbine (lb/hr)	Fire Pump Emission Factor (lb/MMBtu)	Maximum Short-Term Emission Rate for Fire Pump (lb/hr)	Maximum Annual Controlled Emission Rate for All Four Combustion Turbines and HRSGs and Fire Pump (tons/yr)
Ammonia	--	--	--	31.1 E+00 [a]	--	--	544.87
Sulfuric Acid Mist	--	--	--	1.36 E+00 [a]	--	--	23.83
Acetaldehyde	--	--	2.0 E-05	4.1 E-02	7.67 E-04	1.53 E-03	7.29E-01
Acrolein	--	--	3.2 E-06	6.66 E-03	--	--	1.17E-01
Ethylbenzene	--	--	1.6 E-05	3.33 E-02	--	--	5.83E-01
PAH	2.59 E-05	7.01 E-06	1.1 E-06	2.29 E-03	1.68 E-04	3.36 E-04	4.02E-02
Xylenes	--	--	3.2 E-05	6.66 E-02	2.85 E-04	5.70 E-04	1.17E+00
2-Methylnaphthalene [b]	1.2 E-05	3.25 E-06	--	--	--	--	5.69E-05
Anthracene [b]	--	--	--	--	1.87 E-06	3.74 E-06	1.87E-08
Benzo(a)anthracene	--	--	--	--	1.68 E-06	3.36 E-06	1.68E-08
Benzene	1.05 E-03	2.84 E-04	6.0 E-06	1.25 E-02	9.33 E-04	1.87 E-03	2.24E-01
Chrysene [b]	--	--	--	--	3.53 E-07	7.06 E-07	3.53E-09
Dichlorobenzene	6.0 E-04	1.62 E-04	--	--	--	--	2.84E-03
Fluoranthene [b]	1.5 E-06	4.06 E-07	--	--	7.61 E-06	1.52 E-05	7.18E-06
Fluorene [b]	1.4 E-06	3.79 E-07	--	--	2.92 E-05	5.84 E-05	6.93E-06
Formaldehyde	1.125 E-02	3.04 E-03	1.065 E-04	2.22 E-01	1.18 E-03	2.36 E-03	3.93E+00
Hexane	9.0 E-01	2.43 E-01	--	--	--	--	4.27E+00
Naphthalene	3.05 E-04	8.25 E-05	6.5 E-07	1.35 E-03	8.48 E-05	1.70 E-04	2.51E-02
Phenanathrene [b]	8.5 E-06	2.30 E-06	--	--	2.94 E-05	5.88 E-05	4.06E-05
Pyrene [b]	2.5 E-06	6.76 E-07	--	--	4.78 E-06	9.56 E-06	1.19E-05
Toluene	1.7 E-03	4.60 E-04	6.5 E-05	1.35 E-01	4.09 E-04	8.18 E-04	2.38E+00
Total HAPs							1.35 E-01

[a] Maximum short-term emission rate for ammonia and sulfuric acid mist in lb/hr is per combustion turbine and HRSG.
[b] Not identified as a Class A TAP in 173-460-150 WAC or as a Class B TAP in 173-460-160 WAC. Emissions of these pollutants are represented in the emission factor for PAH.

TABLE G–20
Nearby Class I Areas

Class I Area	Distance (kilometers)	State
Eagle Cap Wilderness Area	132	Oregon
Hells Canyon Wilderness Area	140	Oregon/Idaho
Spokane Indian Reservation	140	Washington

- Land use and terrain data were obtained from the USGS internet site (http://edc.usgs.gov/doc/edchome/ndcdb/ndcdb.html).

Figure G-4 shows the CALMET domain with the locations of the surface stations and pseudo precipitation and upper air stations.

CALMET generated a three-dimensional windfield and boundary layer parameters suitable for use by the CALPUFF model. A model domain was established to encompass the generation plant site and the three Class I areas being analyzed. The domain covered a region approximately 109 miles (176 kilometers) by 244 miles (392 kilometers) with a grid resolution of 2.4 miles (4 kilometers). The protocol proposed a 3-mile (5-kilometer) grid; however, better terrain resolution was obtained using a 2.4-mile (4-kilometer) grid. The default options listed in Appendix A of the IWAQM Phase 2 report were used.

Evaluation of Windfields

Windfields were evaluated for specific hours of the year to ensure that the meteorological data processing and windfield development resulted in reasonable data for use in the CALPUFF modeling. The windfield evaluation was completed in consultation with Clint Bowman of Ecology. Windfield plots are presented in Attachment G.

CALPUFF Methodology

The CALPUFF model was run using the output from the CALMET model, source-specific emissions and release characteristics, and building downwash parameters generated for the Class I analysis. Table G-21 provides a summary of some of the parameters chosen for the analysis.

TABLE G-21
CALPUFF Model Options

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_2, HNO_3, NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme with CALPUFF default
Deposition	Wet and Dry
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, stack-tip downwash, partial plume penetration
Dispersion	PG/MPG coefficients
Terrain Effects	Partial plume path adjustment

TABLE G-21
CALPUFF Model Options

Parameter	Setting
Output	Create binary file: output species SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}
Model Processing	Highest concentration predicted
Background Values	Ozone: 40 ppb[1]; Ammonia: 10 ppb[2]

[1] As recommended by Clint Bowman, Washington State Department of Ecology.
[2] Value indicated in the Phase 2 report for grasslands.
HNO_3 = ammonium nitrate.
PG/MPG = Pasquill-Girfford/McElroy-Pooler.
ppb = parts per billion.

Source Inputs

The generation plant will be subject to PSD for NO_X, SO_2, PM_{10}, VOC, and CO. For purposes of the Class I analysis, NO_X, SO_2, and PM_{10} emissions were modeled because they are the pollutants with Class I increments and are the only contributors to sulfate and nitrate deposition. Table G-22 presents emissions for each modeled source. The maximum hourly emission rate was modeled for each pollutant. The condition modeled represents the scenario producing the highest NO_X emissions, which is 100 percent load with duct burner, but no steam injection, under ambient temperature of –20°F.

TABLE G-22
Emission Rates Used in CALPUFF

Source	Emission Rates for SO_2 (lb/hr)	Emission Rates for NO_X (lb/hr)	Emission Rates for PM_{10} (lb/hr)
HRSG 501FD1	4.01	21.0	25.4
HRSG 501FD2	4.01	21.0	25.4
HRSG 501FD3	4.01	21.0	25.4
HRSG 501FD4	4.01	21.0	25.4
Fire-Water Pump	0.1	3.91	0.04

Table G-23 summarizes source characteristics. The increment, deposition, and visibility analyses evaluated project-only impacts. No other sources were included in the Class I analysis.

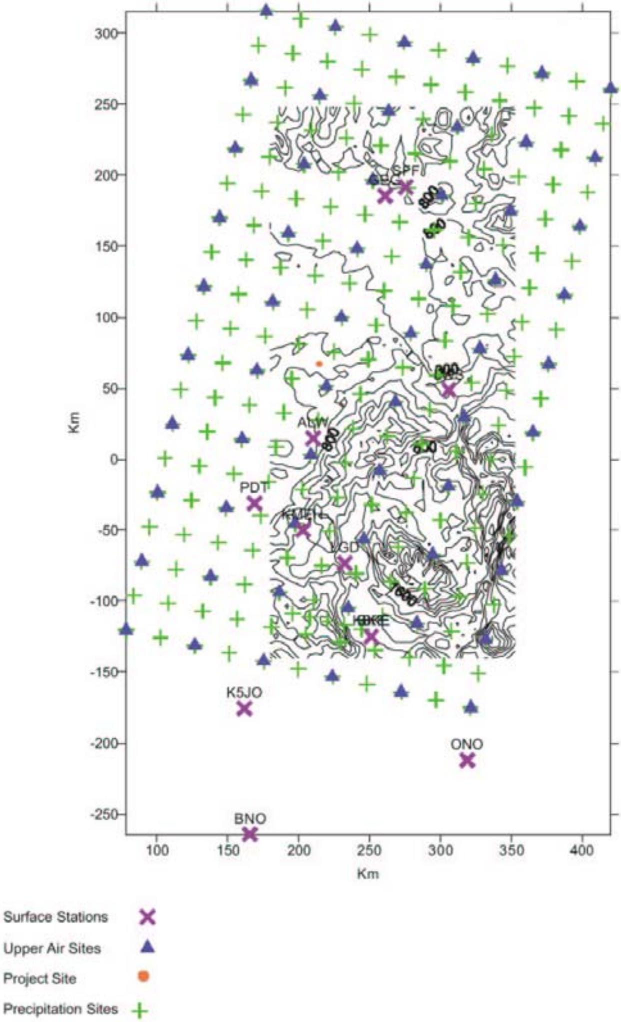


FIGURE G-4
Meteorological Site Locations
Starbuck CALMET Model Domain
STARBUCK POWER PROJECT
STARBUCK, WASHINGTON

TABLE G-23
Source Characteristics

Stack Name	Stack ID	Stack Height [1] (m)	Diameter (m)	Velocity (m/s)	Temperature (K)
HRSGs (all 4)	501FD1,501FD2, 501FD3,501FD4	38.1	5.79	21.46	382
Fire-Water Pump	FP1	10.67	0.25	13.08	722

[1] HRSG stack height for Class I dispersion modeling was conservatively assumed to be 38.1 m (125 ft) as compared to HRSG stack height of 53.3 m (175 ft) used for the Class II dispersion modeling.

Class I Area Receptor Locations

Discrete receptors were placed in each of the Class I areas included in the analysis. These receptors were placed with a spacing of 1.2 miles (2 kilometers) in a gridded area within the Class I area and every 1.2 miles (2 kilometers) along the Class I boundaries. Receptors also were placed at the locations of the maximum and minimum elevations in each Class I area. Figure G-5 shows the Class I areas and the locations of the discrete receptors used in the analyses.

Visibility

Because the Class I areas are more than 31 miles (50 kilometers) from the source, plume impairment will not be evaluated (FLAG).

The regional haze analysis used the modeled concentration and a postprocessor (CALPOST) to calculate the percent change in extinction attributable to the project emissions as compared to the background extinction, or natural conditions, of Hells Canyon, Eagle Cap, and the Spokane Indian Reservation.

The percent change in light extinction (Δ) was calculated using:

$$\Delta = \frac{\Delta b}{b_{back}} * 100$$

where Δb is the incremental increase in light extinction due to the project emissions increase and b_{back} is the background light extinction. The incremental increase in light extinction from the project is given by:

$$\Delta b = 3\left[dc_{NO3} + dc_{SO4} \right] f(RH)$$

where dc_{NO3} and dc_{SO4} are the incremental nitrate and sulfate concentrations in µg/m^3, respectively. Th f(RH) value was calculated on an hourly basis from hourly relative humidity (RH) data from the CALMET runs, and then averaged for each 24-hour period.

The background extinction, b_{back}, was calculated using the equation:

$$b_{back} = b_{hygro} \times f(RH) + b_{NonHygro} + Rayleigh$$

where b_{hygro}, $b_{NonHygro}$, and Rayleigh scattering components are provided in Appendix 2.B of the FLAG Phase I report for each federal Class I area. Because no value is reported for the Spokane Indian Reservation, the value for Hells Canyon was used.

An initial evaluation compared the project-only impacts, using 24-hour maximum concentration from the project emissions increase, to a threshold criteria of a 5 percent change in light extinction over background levels. Because the impacts were below this threshold level, no further analysis was required to assess cumulative impacts.

Deposition

Impacts to both flora and water quality were assessed through an analysis of sulfur (as sulfate ion) and nitrogen (as nitrate and ammonium ions) deposition. Annual deposition rates were determined based on the incremental increase in annual emissions from the proposed project according to methods specified in the IWAQM 2.

Annual deposition rates of NO_X, ammonium nitrate (HNO_3), and NO_3 were calculated by CALPUFF, then converted to nitrogen and summed. Likewise, deposition rates of SO_2 and SO_4^{-2} were converted to sulfur and summed. The CALPOST module was used to perform the conversion and subsequent summation steps.

The calculated deposition rates (in grams per hectare per year [g/ha/yr]) were compared to the significance levels of 5 g/ha/yr for nitrogen and 3 g/ha/yr for sulfur. The significance levels represent 0.1 percent of the upper level of deposition where no significant injury to soils or aquatic resources would be anticipated.

G.3.4.3 Results (Impacts)

Class I PSD Increment

The modeling results were derived directly from CALPOST. Table G-24 provides the results of the Class I PSD increment analysis. The maximum PSD increment is well below proposed Class I significance levels for all criteria pollutants in all Class I areas.

TABLE G-24
Class I Ambient Air Quality Results for SPP

Area	SO_2 Annual (μg/m^3)	SO_2 24-hour (μg/m^3)	SO_2 3-hour (μg/m^3)	PM_{10} Annual (μg/m^3)	PM_{10} 24-hour (μg/m^3)	NO_X Annual (μg/m^3)
Eagle Cap Wilderness Area	8.0E-05	2.8E-03	1.2E-02	7.8E-04	2.0E-02	8.8E-05
Hells Canyon Wilderness Area	1.2E-04	2.6E-03	1.1E-02	1.1E-03	2.0E-02	2.1E-04
Spokane Indian Reservation	2.4E-04	1.1E-02	3.6E-02	2.0E-03	9.0E-02	5.5E-04
EPA Class I Significance Level	**0.1**	**0.2**	**1.0**	**0.2**	**0.3**	**0.1**
Class I Increment	**2**	**5**	**25**	**4**	**8**	**2.5**

Visibility Impacts

Table G-25 provides visibility impacts for each Class I area. As shown, impacts are less than the 5 percent change in extinction coefficient guidance criteria (FLAG) for each Class I area.

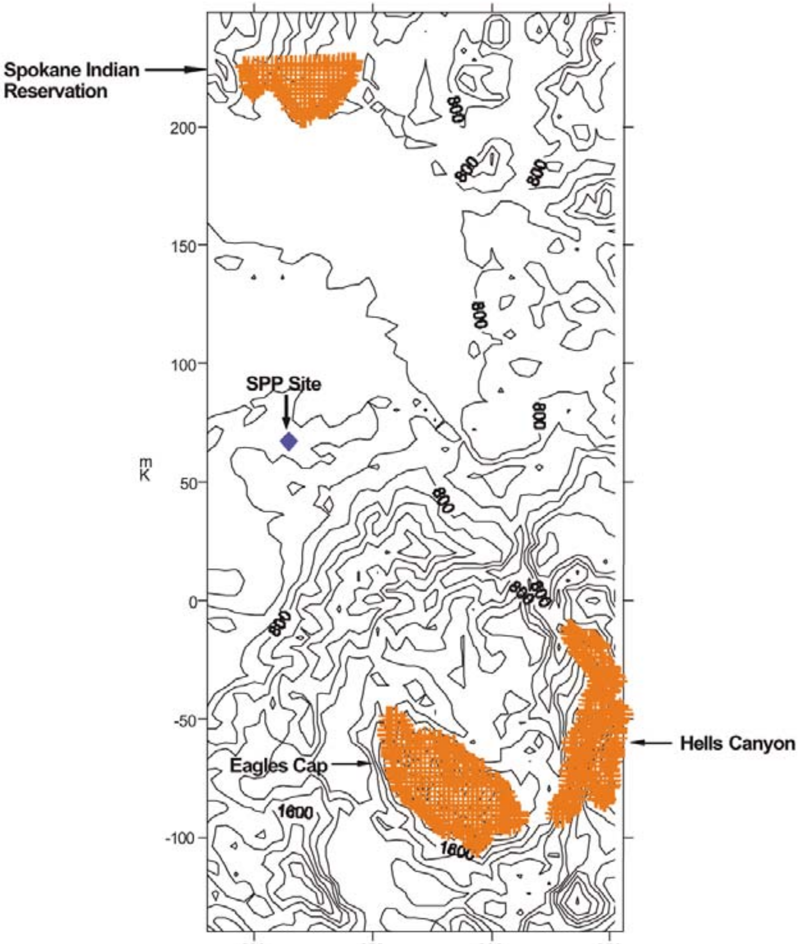


FIGURE G-5
Class I Area Receptors
SPP CALPUFF Model Domain
STARBUCK POWER PROJECT
STARBUCK, WASHINGTON

TABLE G-25
Visibility Analysis Results
Maximum Percent Extinction Change

Area	Day	Year	Receptor Coordinate X (km)*	Receptor Coordinate Y (km)*	b_{ext} Modeled (1/Mm)	b_{ext} Background (1/Mm)	Extinction Change (%)
Eagle Cap Wilderness Area	263	1998	303.907	-78.598	0.066	16.757	0.4
Hells Canyon Wilderness Area	291	1998	332.512	-12.00	0.138	17.451	0.79
Spokane Indian Reservation	344	1998	229.7	206.983	0.313	16.662	1.88

* Lambert conformal coordinate system with a reference north latitude of 46 degrees and a reference west longitude of 121 degrees and standard parallels of 42.5 and 48 degrees north latitude and standard meridian of 121 degrees west longitude.

Mm = megameter.

G.3.5 Deposition Impacts

Table G-26 summarizes deposition results for nitrogen and sulfur for each Class I area. Incremental deposition rates attributable to the generation plant are less than 5 g/ha/yr for nitrogen and 3 g/ha/yr for sulfur at each Class I area. These rates are considered insignificant (R. Bachman, USFS, response to Starbuck modeling protocol).

TABLE G-26
Summary of Total N and S Deposition Results

	Total N g/ha/yr	Total S g/ha/yr
Eagle Cap Wilderness Area	0.3	0.1
Hells Canyon Wilderness Area	0.2	0.1
Spokane Indian Reservation	0.5	0.2

g/ha/yr = grams per hectare per year.

Figures G-6 through G-8 are plots showing each Class I area, including the receptor grid and modeling results.

G.3.5.1 Documentation

Copies of Class I files for CALMET and CALPUFF included in Attachment H are available electronically upon request.

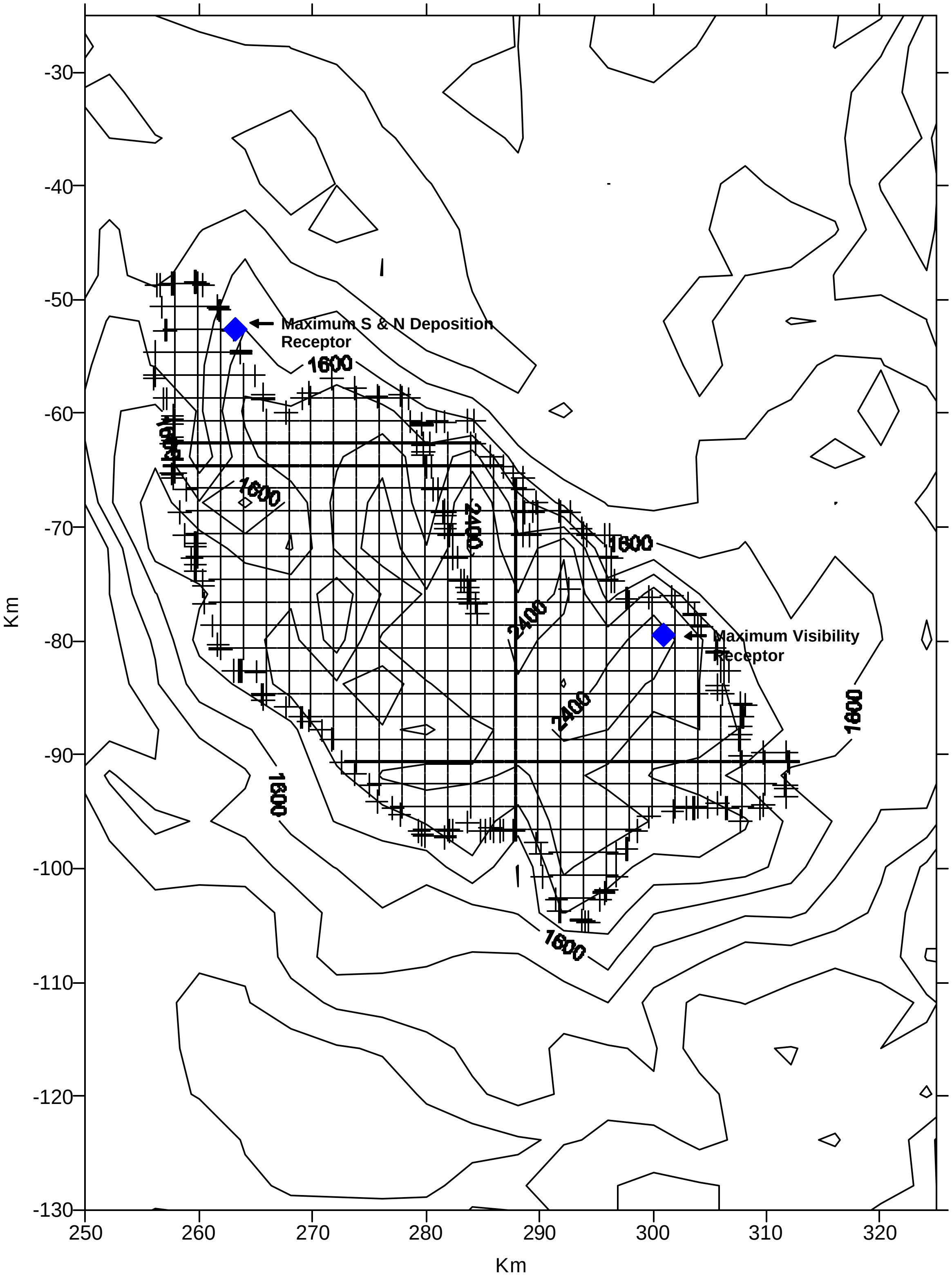


Figure G-6
Eagle Cap Wilderness Area
Class I Receptors and Maximum Impact Locations

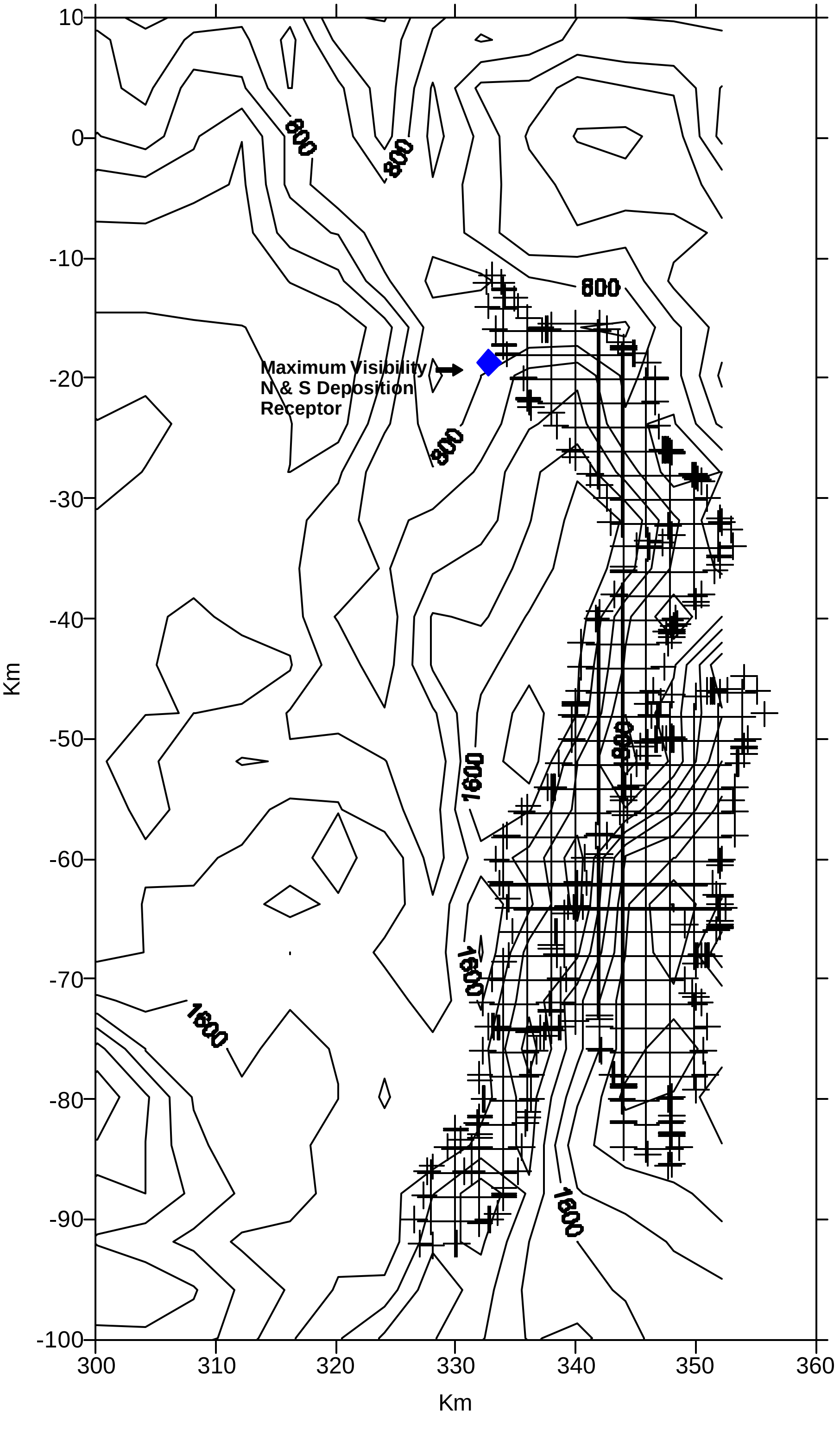


Figure G-7
Hells Canyon Wilderness Area
Class I Receptors and Maximum
Impact Locations

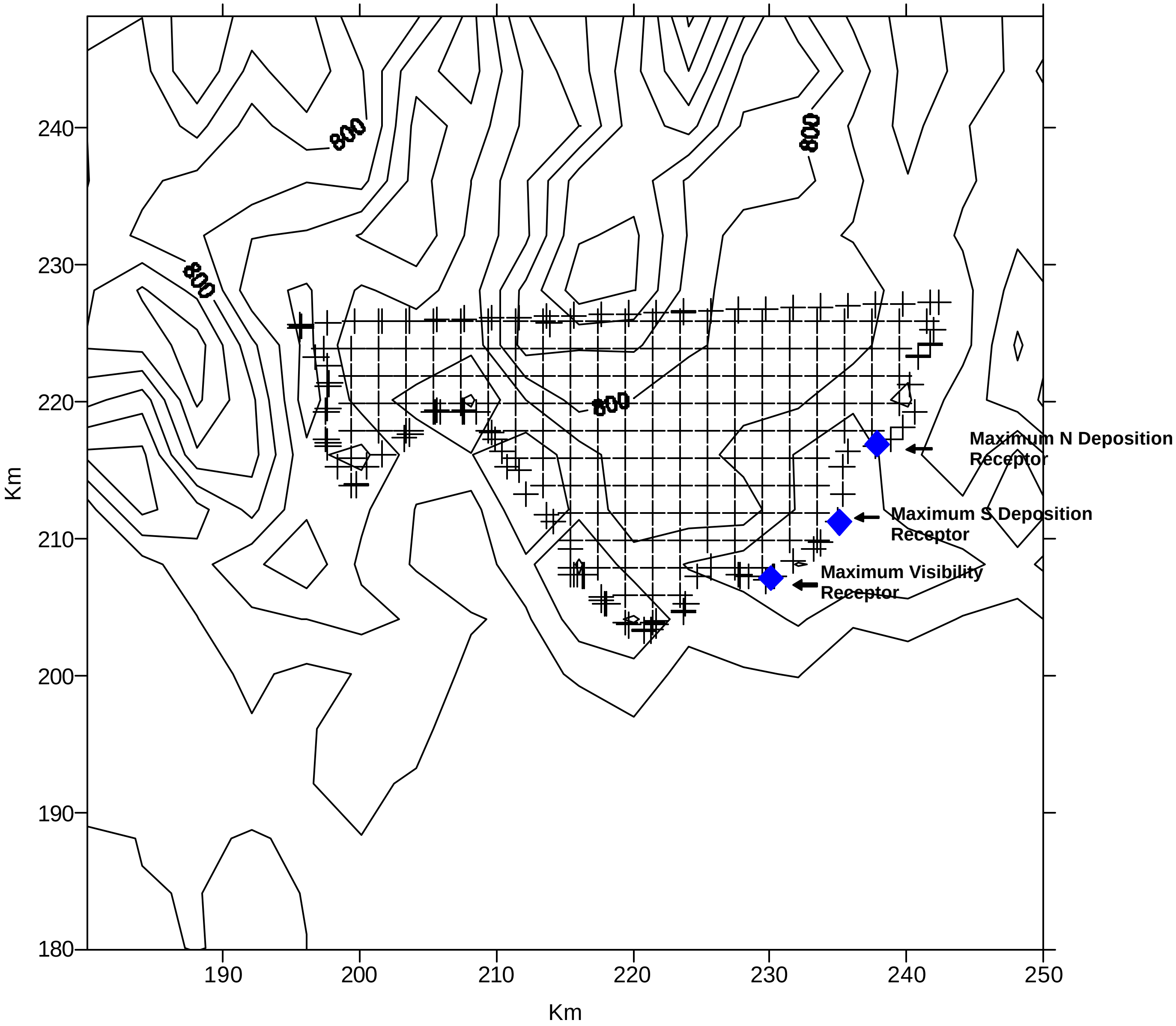


Figure G-8
Spokane Indian Reservation
Class I Receptors and Maximum
Impact Locations

ATTACHMENT A

Onsite Meteorological Monitoring

Monitoring requirements under prevention of significant deterioration (PSD) are defined in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-07), and Quality Assurance Handbook for Air Pollution Measurement Systems Volume IV-Meteorological Measurements,(EPA/600/R-94/038d-April 1994). An onsite meteorological monitoring station must be operated in such a manner to meet these minimum requirements.

The Starbuck Power Project (SPP) onsite monitoring station design and operation meets these requirements by installing and operating the station focusing on the requirements of PSD. A data recovery rate of 90 percent is required under PSD.

A.1 Starbuck Power Project Meteorological Station

The SPP meteorological station consists of a 10-meter-tall aluminum tower with instruments mounted on the tower. The tower is supported by a concrete base and anchored in place by three guy wires. The tower base is hinged so the tower can be tilted down to gain access to the instruments for inspection, maintenance, calibration, and auditing.

The station operates continuously to monitor meteorological parameters of wind speed, direction, and temperature. A data logger capable of capturing and processing output signals from each instrument is mounted on the tower. U.S. Environmental Protection Agency (EPA) monitoring guidance asks that weekly site visits be made to download data and ensure proper operation.

The station collects data that meet the minimum requirements for collecting onsite data for permitting and modeling under EPA's PSD regulations.

A.1.1 Description of Meteorological Instrumentation

The meteorological instrumentation is manufactured by Met One Instruments of Grants Pass, Oregon. All instrumentation meets or exceeds EPA's PSD specifications for meteorological data collection.

The following meteorological parameters are measured:

- WS10 Wind Speed – 10 meters (miles per hour)
- WD10 Wind Direction – 10 meters (degrees)
- SG10 Standard Deviation of Wind Direction Fluctuations (Sigma A)– 10 meters (degrees)
- AT2 Air Temperature – 2 meters (°F)

Wind speed and wind direction are measured with the Met One Model 034A Wind Sensor. This instrument features both speed and direction measurement by a single sensor.

The Met One Model 062A Temperature Sensor is used to measure ambient temperature.

A Met One Instruments Automet™ data logger serves as the data acquisition system (DAS) for the station. Each parameter is scanned once per second and averaged over an hour. The DAS then stores these hourly averages in nonvolatile memory for retrieval. The DAS also computes the Sigma A value according to EPA recommended algorithms.

A.1.3 Station Operation

Operation of the meteorological station is performed by local personnel who have been trained by CH2M HILL meteorological monitoring staff familiar with the EPA guidance documents for operation of meteorological stations.

Monitoring guidance documents suggest that a meteorological station be visited at least once per week. Duties conducted during visits to the station include verifying proper operation of the instruments, downloading data to a storage device, and performing routine quality control checks. This process also serves as a tool for identifying and correcting instrument malfunctions in a timely manner, thereby minimizing loss of data.

The schedule of operations for the weather station is as follows:

- At least once per week the station will be visited and an inspection of the instruments will take place.
- On a quarterly basis, CH2M HILL will perform a maintenance inspection of the station.
- Quality assurance performance audits and field calibrations will occur within 30 days of startup, every 3 months during operation, and within 30 days of station shutdown.

A.1.4 Weekly Site Visits

As part of the quality assurance/quality control (QA/QC) program, a site logbook and data comparison form were developed to serve as the official site documentation. An example of the data comparison form is provided below. The field operator completes this form during each site visit. All QA/QC and maintenance activities are noted in the logbook.

At a minimum of once a week, a field operator visits each site and conducts an inspection, following (but not limited to) the items listed below. The bulleted items below are a step-by-step inspection procedure that corresponds to the items to be checked. Any extraordinary activities or circumstances are noted in the logbook.

- Visually inspect the meteorological tower and sensors for damage. Visually estimate wind speed and direction by observing the spinning of the cups and the direction in which the vane is pointed. Check the temperature aspirator motors to verify they are operating correctly.
- Verify that the data logger time is correct within 15 minutes. All time should be in Pacific Standard Time (PST). If the time needs to be reset, inform CH2M HILL personnel so they can assist via telephone.

- Compare the instantaneous readings of the data logger with observed actual readings.
- Check for signs of vandalism to the meteorological tower. Report any damage to the appropriate persons.
- Determine if the wind vane is moving freely and is not bent or broken.
- Record the time of day (use military time) from the operator's watch.
- Record the data logger time.
- Download the data since the last visit to the data transfer module. Ship the module to CH2M HILL in Portland, Oregon, for downloading.
- Determine if the data logger is recording valid data. Record the instantaneous data values. Decide if the values are reasonable. If data are questionable, consult CH2M HILL personnel for assistance.
- Make notes in the logbook of any unusual circumstances and significant weather events (high winds, cold or hot temperatures, heavy snow, ice buildup on sensors, birds landing on sensors).
- If any of the above checks indicate malfunctions or invalid data, then the appropriate CH2M HILL personnel are to be notified as soon as possible. All activities and/or problems are to be thoroughly documented in the logbook. The operator should make sure the date, time of the visit/inspection, site, and his/her initials appear on all pages of the current logbook.

Table A-1 is an example of the station checklist used for comparing the instantaneous data logger with the actual, estimated meteorological conditions.

TABLE A-1
Meteorological Station Checklist Data Comparison

Date
Wind Speed
Observed
Data Logger
Wind Direction
Observed
Data Logger
Temperature
Observed
Data Logger

A.1.5 Data Validation

Data retrieved weekly from the monitoring system are validated at two levels. The first level (or initial screening of the data) serves to diagnose instrumentation and systematic problems. This screening check is performed by the site operator during each site visit. A site observation log sheet entry is made during each site visit.

The second data validation level is executed in batches, usually monthly. Once the data have been retrieved from the field, they are loaded into a Microsoft Access® database. Specific queries are run on the data to screen it for possible outliers. These screening rules are based on EPA monitoring guidelines, manufacturers' equipment specifications, and sound meteorological judgment. The application of these rules results in flagging out-of-range or outlier data. These flags mark the data that require more extensive review. After outliers are defined, the entire data set, including outliers, is reviewed by an experienced meteorologist. During this step, validity of each hour of data is determined. This final step in data validation also incorporates the findings of quarterly performance audits and site visit logs.

A.2 Quality Assurance

The QA program for the meteorological monitoring project was developed based on accepted procedures and guidance documents for conducting meteorological monitoring. These written documents were developed by the EPA.

The following parameters are used to define the QA program's success:

- Completeness is the ratio of the number of actual valid data obtained through the measurement system to the number of data points expected or possible under normal conditions. Completeness will be calculated for the generation plant in the following manner:

  $$\text{Data completeness} = \frac{\text{Number of valid readings}}{\text{Number of possible readings}} \times 100$$

  The PSD requirement for data completeness is 90 percent.

- Accuracy is determined by following EPA guidelines for conducting meteorological performance audits of each measurement parameter. Data must meet the accuracy recommendations of EPA guidance to be considered valid.

A.2.1 Meteorological Performance Audits

An audit is an independent assessment of the accuracy of the data. Independence is achieved by having an operator other than the one conducting the routine field measurements perform the audit, and by using audit standards and equipment that differ from those routinely used in monitoring. The audit should be a true assessment of the measurement process under normal operations without any special preparation or adjustment of the system. Proper implementation of an auditing program ensures the integrity of the data and assesses the data for accuracy.

The auditing program checks the accuracy of each piece of equipment. The audits also check the DAS to ensure it is operating properly and that data are reported accurately.

A.2.1.1 Meteorological Audit Procedures

Meteorological performance audits are conducted by CH2M HILL according to EPA criteria defined in EPA/600/R-94/038d, *Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV, Meteorological Methods,* April 1994, and *Onsite Meteorological Program Guidance For Regulatory Modeling Applications,* EPA-450/4-87-013, August 1995. EPA guidance suggests conducting audits within 30 days of station startup; every 6 months during operation; after significant downtime or major repairs, if the station is relocated; and within 30 days of station shutdown.

To meet this rigorous monitoring schedule, performance audits are conducted on a quarterly schedule. This exceeds the EPA guidance, which calls for audits every 6 months. The audits are performed by individuals experienced in meteorological monitoring who are not involved in the routine operation of the station. The audits also consist of challenging the meteorological instruments with a series of test instruments to determine operational characteristics.

During the audit, items such as sensors, cups, vanes, shields, and cables are inspected to determine whether any unusual wear has occurred. Any wear is identified in the comments portion on the audit form. The audits are performed using a calibration/test instrumentation audit package for onsite meteorological sensor evaluation. The package contains a series of test instruments for determining bearing condition, wind vane orientation, wind speed accuracy from known frequencies and rotational speeds, wind direction accuracy and linearity, and temperature accuracy in comparison to National Institute of Standards and Technology (NIST) transfer standards. All audit instruments are certified against authoritative standards as required by the monitoring guidance. For each sensor, the results are checked by using a digital voltmeter and compared to the DAS output.

Table A-2 summarizes EPA recommended accuracies for each meteorological instrument. The pass/fail criteria for audit results are based on these accuracies.

TABLE A-2
Recommended System Accuracies and Resolutions

Meteorological Variable	System Accuracy	Measurement Resolution
Wind Speed (horizontal and vertical)	± (0.2 m/s + 5% of observed)	0.1 m/s
Wind Direction (azimuth and elevation)	± 5 degrees	1.0 degree
Ambient Temperature	± 0.5 °C	0.1 °C
Vertical Temperature Difference	± 0.1 °C	0.02 °C
Dew Point Temperature	± 1.5 °C	0.1 °C
Precipitation	± 10% of observed or ± 0.5 mm	0.3 mm
Barometric Pressure	± 3 mb (0.3 kPa)	0.5 mb
Solar Radiation	± 5% of observed	10 Watts/m^2
Time	± 5 minutes	

Source: EPA 450/4-87-013.
kPA = kilopascal
mb = millibar

A.2.2 Performance Audit Procedures

The following sections describe the specific procedures followed for auditing each instrument.

Wind Speed

The wind speed sensor is challenged for accuracy with a variable synchronous motor that simulates three known wind speeds. Resultant sensor wind speeds are compared to the expected speeds. A torque watch test is also performed to determine starting torque, threshold, and thereby bearing acceptability. If the system exhibits a starting threshold of greater than 0.5 meters per second, then the wind speed sensor fails the audit.

Wind Direction

The wind direction sensor's true north orientation is verified by using a transit compass and tripod. The wind direction sensor is rotated in 30-degree increments (as determined by a protractor-type device), and the output is checked at each point. If any of the responses throughout the 360-degree rotation are greater than ± 5 degrees from the correct wind direction, then the sensor fails the audit. Starting thresholds and bearing wear of the wind direction sensor also are tested with a torque watch in a manner similar to that described for wind speed. A sensor response of greater than 0.5 meters per second fails the audit.

Temperature

The temperature sensor is checked at two temperatures (temperatures of an ice water bath and the ambient air). The sensor's responses to an ice slurry and ambient air are compared to an annually calibrated NIST traceable thermometer. The temperature response must be within ±0.5°C of the reference temperature to pass the audit.

A.2.3 Meteorological Audit Results

After completion of each audit, each instrument is calibrated, if necessary, according to the manufacturer's specifications. The auditor reviews the preliminary findings with the field operator after completion of the field audit. A summary report is completed after each audit. CH2M HILL has developed an audit pass/fail checklist. An example appears at the end of this attachment.

Meteorological audits were conducted upon station startup on December 28, 2000, and again on March 28, 2001, and June 23, 2001. All parameters passed all audit tests. The audit results further prove to validate the data set according to EPA guidelines.

A.3 Summary of Meteorological Data

The generation plant onsite meteorological data set used for input for conducting dispersion modeling is for the period January 20, 2001, through July 5, 2001. The data validation process determined that a total of 21 hours of data were invalid during this period. These data were invalidated because they occurred while the field operator or auditors were conducting preventive maintenance and QA activities. The resulting data completeness was greater than 90 percent for each month of data. The data completeness for this period of record was 99.5 percent. This exceeds the PSD criteria of 90 percent.

The missing 9 hours were left as missing; that is, no interpolation was conducted to fill in these missing hours. The meteorological data then were input into the preprocessor.

A.3.1 Meteorological Data Processing

Meteorological data from the onsite station were run in the EPA meteorological processing program MPRM to prepare the meteorological input file for the ISCST3 modeling. Upper air data from Spokane, Washington, were used to calculate mixing heights. Stability classes were calculated in MPRM using the onsite horizontal wind direction standard deviation.

During the period from January 20 to February 28, 2001, the wind speed sensor experienced intermittent failures. During that period, a total of 345 hours of wind speed data were determined to be missing. Of that data, 175 hours were filled by interpolation as defined by procedures found in EPA's *Guideline on Air Quality Modeling*. Of the remaining 175 hours, 170 were treated as calms and 5 were treated as missing ISCST3.

A.4 References

U.S. Environmental Protection Agency (EPA). 1994. *Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV, Meteorological Methods.* (EPA/600/R-94/038d, April 1994).

U.S. Environmental Protection Agency (EPA). 1995. *Onsite Meteorological Program Guidance for Regulatory Modeling Applications.* (EPA-450/4-87-013, August 1995).

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Meteorological Audit Pass/Fail Checklist

Date ________________________

Site Location ________________________

Client ________________________

Project Number ________________________

Auditor ________________________

Audit Pass/Fail Criteria

Meteorological Variable	Pass/Fail Criteria	Results, Pass (P) or Fail (F)
Wind Speed (horizontal and vertical)	± (0.2 m/s + 5% of observed value)	
Wind Direction (azimuth and elevation)	± 5 degrees	
Ambient Temperature	± 0.5 °C	
Delta Temperature	± 0.1 °C	
Dew Point	± 1.5 °C	
Precipitation	± 10% of observed value or ± 0.5 mm	
Barometric Pressure	± 3 mb (0.3 kPa)	
Solar Radiation	± 5% of observed value	
Time	± 5 minutes	

Conversion factors:

1 mph = 0.45 m/s	1 m/s = 2.24 mph
degrees C to degrees F	***degrees F to Degrees C***
C=(5/9)(F-32)	F=(9/5)C+32

ATTACHMENT B

Air Dispersion Modeling Protocol

Campardi

CH2MHILL TRANSMITTAL

To: Washington Department of Ecology
P.O. Box 47600
Olympia, WA 98504

From: Julianne Guilbault

Attn: Clint Bowman

Date: March 27, 2001

Re:

We Are Sending You:

☒ Attached
Under separate cover via
Shop Drawings
Documents
Tracings
Prints
Specifications
Catalogs
Copy of letter
Other:

Quantity	Description
1 copy	*Air Dispersion Modeling Protocol for the Starbuck Power Project – Starbuck, Washington*

If material received is not as listed, please notify us at once

Copy To: Bob Bachman/USDA Forrest Service
Don Fields/PPL Global
Mike Elmer/Starbuck Power Company, L.L.C

Air Dispersion Modeling Protocol for the Starbuck Power Project Starbuck, Washington

Prepared for:

Starbuck Power Company, LLC

Submitted to:

Washington State Department of Ecology

March 2001

Prepared By:

CH2MHILL

Introduction

Starbuck Power Company, LLC (SPC) proposes to construct a nominal 1,200 megawatt (MW) natural gas fueled, combustion turbine power plant in southeastern Washington. The plant will occupy the southeast portion of a 100 acre site located approximately 6 miles northwest of the town of Starbuck in Columbia County. Figure 1 presents a location map of the proposed project.

As proposed, the Starbuck Power Project would generate approximately 1,200 MW of electrical power using combined-cycle combustion gas turbines (CTGs), heat recovery steam generators (HRSGs), steam turbine generators (STGs), and air-cooled condensers. The project would include four as yet undetermined combustion turbines, four three-pressure HRSGs equipped with supplemental duct firing, two STGs, two air-cooled condensers, and associated support equipment. Other key plant facilities include the switchyard, control and administration facilities, parking and transfer areas for a mobile water treatment facility, water storage facilities, and a gas metering station.

The electrical generation equipment would be arranged within two "power blocks," each in a "two-on-one" configuration. In a two-on-one configuration, each of two CTGs is directly connected to an electric generator and a HRSG. Steam produced by the two HRSGs is combined and directed to a single STG.

The preliminary analysis of the annual emissions for the project is shown in Table 1 along with the Prevention of Significant Deterioration (PSD) significant emission rates. These SPC emission rates conservatively assume that the combustion gas turbines are operating continuously (i.e. 8760 hours per year) at full capacity and are subject to change as additional emission information is received.

Table 1
Preliminary Annual Emissions (tons per year)

Pollutant	SPC Project Emission Rates[1]	Significant Emission Rate
NOx	400	40
SO_2	70	40
CO	300	100
VOC	50	40
PM_{10}	350	15

[1] Emissions data is preliminary and is subject to change. Dispersion modeling will be performed with final emissions data.

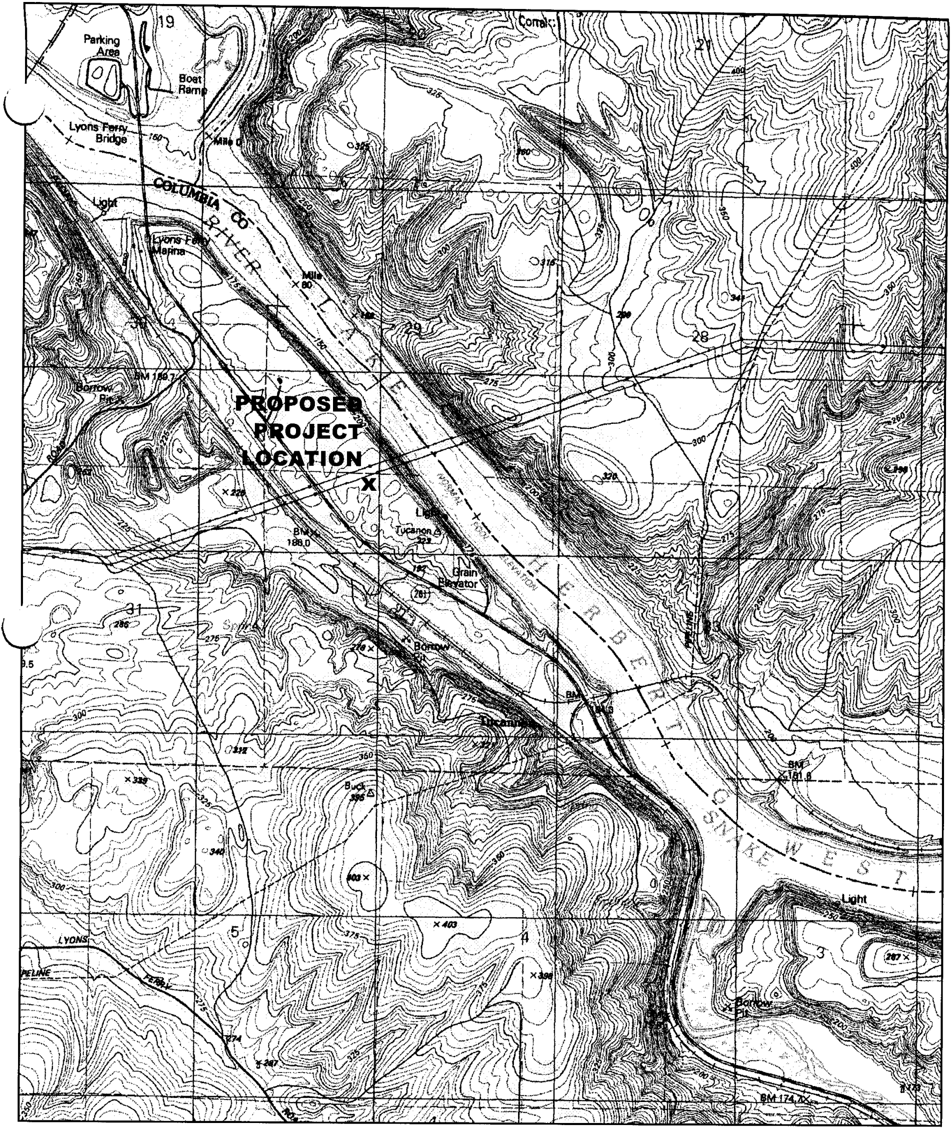

Figure 1

CH2MHILL

Proposed Project Location

The applicable PSD major source threshold is 100 tons per year of any regulated pollutant. Because the facility will have emissions of a regulated pollutant that exceed this threshold, it is subject to the PSD program. Once the major source threshold is triggered for any one pollutant, then the source is subject to PSD for all pollutants that exceed the PSD significant emission rate (SER) (see Table 1). Under PSD, a modeling analysis is required for each pollutant subject to PSD to determine the air quality impacts from the proposed source. Specifically, the impacts of NO_x, CO, SO_2, and PM_{10} will be compared to state and national ambient air quality standards (AAQS). Emissions of NOx, SO_2, and PM_{10} will also be modeled for comparison to the PSD increments. VOC emissions are regulated as a precursor to ozone. Ozone is a regional scale pollutant formed through chemical reactions over time and distance. Although VOC emissions may exceed the 40 ton threshold, modeling single source impacts for ozone is not possible with current modeling tools. Because of the relatively low emissions of VOC, modeling will not be required for that pollutant. Other PSD requirements, such as a Best Available Control Technology (BACT) evaluation, will apply to VOC emissions.

SPC must also assess impacts on visibility, soils and vegetation and assess the impact on nearby federally designated Class I areas. An investigation concluded that there are no Class I areas within 100 kilometers (km) of the proposed facility. There are two Federal Class I areas within 200 km of the proposed SPC facility: the Eagle Cap Wilderness Area; and the Hells Canyon Wilderness Area. There is also one non-Federal Class I area within 200 km of the proposed site: the Spokane Indian Reservation. SPC will, therefore, conduct modeling for comparison to applicable Class I increments, as well as conduct the required air quality related values analysis for Federal Class I areas.

Under Washington state regulation (WAC 173-460), a new source must also evaluate emissions of toxic air pollutants and evaluate the impact on ambient air quality. This modeling protocol summarizes the modeling methodology that will be used to evaluate the air quality impacts of the proposed facility. This protocol has been prepared using methodologies consistent with those described in the U.S. Environmental Protection Agency (EPA) Guideline on Air Quality Modeling (GAQM), *The Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report* (Federal Register Vol. 66, No. 2, January 3, 2001) and in the *Interagency Working Group on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.* (EPA-454/R-98-019), and on conversations with staff at the Washington State Department of Ecology (Ecology).

Dispersion Modeling Methodology

Modeling Options and Assumptions

For the short range analysis, CH2M HILL proposes to use the EPA-approved ISCST3 (Version 00101) model. ISCST3 will be run with the following options.

- Regulatory default options
- Direction-specific building downwash

- Actual receptor elevations
- Complex/intermediate terrain algorithms (if appropriate)

The affect of building downwash will be considered by reviewing stack and building configurations. The direction-specific building-downwash parameters used in ISCST3 will be calculated using the EPA Building Profile Input Program (BPIP, Version 95086).

ISCST3 allows the selection of either rural or urban dispersion coefficients. Auer's (1978) land-use classification method was used to determine the dispersion mode for this analysis. Because more than 50 percent of the land use within three kilometers around the proposed facility appears to be rural, the model will be run using the rural dispersion coefficients.

Meteorology

A meteorological monitoring station has been installed at the proposed SPC site and is currently collecting data. We propose to conduct modeling with the first 3 months of data collected, and reevaluate the impacts upon collection of one year's worth of data. The surface data will be processed with upper air data collected at the Spokane airport National Weather Service monitoring station. The three months of data will include the months of January, February, and March. This should adequately cover the winter period when air stagnation is most likely to occur in this valley location and modeled impacts would be expected to be the highest. Using this data for modeling should result in worst case impacts. This approach has been discussed with Clint Bowman of Ecology

Receptors

The ISCST3 model will be run first with a nested Cartesian grid of 100 meter-spaced receptors within a 500-meter grid. The 100-meter grid will extend approximately 1 km around the facility, while the 500-meter grid will extend approximately 5 km. In addition, receptors will be placed at 50 meter intervals around the property boundary. A second run will be made with fine grid receptors centered on the coarse grid maximum receptor to resolve the maximum impact area. Receptor elevations will be extracted from USGS Digital Elevation Model (DEM) files.

Evaluation Procedure

Preliminary Analysis – Criteria Pollutants

Using the stack parameters, receptor grids, and meteorological data, the facilities will be modeled using the following four scenarios: 100% load rate with duct firing, 100% load rate without duct firing, 75 % load rate, and 60% load. For the short-term averages (1-, 3-, 8- and 24-hour), the maximum short-term emissions rates will be used for the entire meteorological data set. For the annual averages, annualized emission rates that take into account the hours of operation will be used.

First, modeling will be conducted to determine whether the proposed emissions will result in an impact greater than the applicable significant impact level (SIL). The SILs, along with the applicable standards and increments, are shown in Table 2. If the predicted impacts are not significant (that is, less than the SIL), the modeling is complete for that pollutant under that averaging time. If impacts are significant, a more refined analysis, as described below, will be conducted.

Table 2
Regulatory Standards and Significance Levels

Pollutant	Averaging Period	National Primary AAQS ($\mu g/m^3$)	National Secondary AAQS ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
CO	8-Hour	10,000	10,000	---	500
	1-Hour	40,000	40,000	---	2,000
NO_2	Annual	100	100	25	1
PM_{10}	Annual (arithmetic)	50	50	17	1
	24-Hour	150	150	30	5
SO_2	Annual (arithmetic)	80	80	20	1
	24-Hour	365	365	91	5
	3-Hour	1300	1300	512	25

Refined Analyses – Criteria Pollutants

Comparison to the Ambient Air Quality Standards

For those pollutants (by averaging time) with concentrations greater than the SILs, an additional analysis will be conducted to determine the maximum concentration for comparison to the AAQS. This maximum concentration will include contributions from the facility, nearby sources, and ambient background concentrations. For this analysis, only receptors that have impacts greater than the SIL for that particular pollutant and averaging time will be evaluated. It is assumed that Ecology will provide the competing sources locations, emissions and stack parameters. A tiered approach will be used to determine which competing sources to include in the modeling:

1. From 0 to 15 kilometers from the SPC site, all permitted sources with emissions greater than the pollutant SER;
2. From 15 kilometers to 50 kilometers, only major sources for the pollutant of concern.

To determine the background concentrations for the analysis, the EPA's Aerometric Information Retrieval System (AIRS) was reviewed to identify the pollutant monitoring stations nearest the SPC, which would also be representative of conditions there. This is an electronic database available via the EPA website (www.epa.gov/airsdata) which provides pollutant monitoring data through December, 2000.

The closest ambient pollutant monitoring sites are for PM_{10}. The nearest PM_{10} monitoring stations are located in Walla Walla, Washington, and Lewiston, Idaho. We propose to evaluate both sets of data and, upon choosing the most appropriate and complete data, use the average of the most current 5 years of data for the annual average background concentration. The highest 24-hour average concentration, excluding those attributable to natural events such as dust storms, will be used as the short-term background concentration.

There are no NOx or SO_2 monitoring sites in eastern Washington. In 1983, Pratt and others recorded average background NOx concentrations of 0.1 to 7.2 parts per million (ppm) (0.16 to 11 $\mu g/m^3$) in rural parts of the United States (Smith, 1990). In the absence of any other data, we propose to use 11 $\mu g/m^3$ as the background NOx concentration. This value was used in the modeling for the Northwest Regional Power Facility in Creston, Washington (1993). We will investigate whether rural SO_2 concentration data have been collected and are suitable for use as background for this analysis.

The nearest CO monitors are located in Spokane. Most of these are not representative of the SPC site since Spokane is a CO nonattainment area and the monitors are typically sited near high volume traffic corridors. However, a monitoring station at Gonzaga University is representative of suburban conditions and may be more suitable for establishing background for the SPC site. This data will be evaluated to determine its applicability to for the project site.

PSD Increment

If the concentrations of NOx, PM10 and SO_2 (by averaging time) are greater than their respective SILs, an additional analysis will be conducted to determine the PSD increment consumption. As with the AAQS evaluation, only receptors with concentrations greater than the SIL will be evaluated. It is assumed that Ecology will provide the source information (that is, locations, emissions and stack parameters) for the nearby increment consuming and expanding sources.

Toxic Dispersion Modeling

Washington Administrative Code (WAC) 173-460 requires evaluation of listed toxic air pollutants (TAPs) to demonstrate compliance with the acceptable source impact levels (ASILs). A preliminary analysis will be conducted in which the estimated quantity of the listed TAPs from the proposed SPC project is compared to the small quantity emission rates (SQER) specified in the regulation. Those pollutants whose emissions are predicted to exceed the SQER will be modeled and their concentration compared to the ASIL

Additional Impact Analysis

PSD regulations require the impacts to visibility, vegetation, and soils be evaluated. For the impact to visibility, vegetation and soils, the secondary ambient air quality standard will be used. The secondary air quality standards were promulgated to protect public welfare including impacts to non-human health resources.

Class I Area Impact Analysis

As indicated in Table 3, there are two Federal Class I areas within 200 kilometers of the SPC proposed site, and one non-Federal Class I area. The Federal Land Manager responsible for the protection of the Federal Class I areas is the USDA Forest Service (USFS) for the Hells Canyon and Eagle Cap Wilderness Areas. The Spokane Tribe is the land manager for the Spokane Indian Reservation.

Modeling to determine compliance with the Class I PSD increments will be performed using the CALMET/CALPUFF modeling system. Model results will also be used for comparison to the criteria established for Air Quality Related Values (AQRV's) in Federal Class I areas. The analysis will follow guidance provided in *The Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report* (Federal Register Vol. 66, No. 2, January 3, 2001) and in the *Interagency Working Group on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.* (EPA-454/R-98-019).

The Class I PSD Increment for NOx is 2.5 $\mu g/m^3$. However, in the proposed New Source Review rules (1996), EPA included two proposed Class I area significance levels, one proposed by EPA and the other by the FLM. The proposed EPA annual NOx Class I significance level is 0.1 $\mu g/m^3$, and the proposed FLM significance level is 0.03 $\mu g/m^3$. Both of these proposed significance levels will be evaluated.

The Class I PSD Increments are shown in Table 4.

Table 3
Distance to Class I Areas

Class I Area	Distance (km)	State
Eagle Cap Wilderness Area	132	Oregon
Hells Canyon Wilderness Area	140	Oregon/Idaho
Spokane Indian Reservation	140	Washington

Table 4
Class I PSD Increments

Pollutant/Averaging Time	PSD Increment (ug/m^3)
PM-10, annual	4
PM-10, 24 hour	8
SO2, annual	2
SO2, 24 hour	5
SO2, 3 hour	25
NO2, annual	2.5

Based on consultation with Bob Bachman of the USFS, we propose to evaluate visibility and wet and dry deposition for each of the Federal Class I areas.

The methodology used for the modeling as well as the approach used to assess each AQRV are described in the following sections.

CALMET Methodology

The CALMET model will be run using the following input data:

- Mesocale Model – Generation 5 (MM5) data for the one year period from March 16, 1998, to March 15, 1999
- Hourly surface, precipitation and twice daily upper air meteorological data for the same period
- Land use and terrain data obtained from the U.S. Geological Survey (USGS) internet site

CALMET will generate a three dimensional wind field and boundary layer parameters suitable for use by the CALPUFF model. A model domain will be established to encompass the SPC site and the three Class I areas being analyzed. The domain will cover a region approximately 160 km by 335 km with a grid resolution of 5 km. The default options listed in Appendix A of the IWAQM Phase 2 report will be used.

Wind fields will be evaluated to verify the reasonableness of the CALMET data generation. A set of conditions to be used in this analysis will be determined following consultation with Ecology staff.

CALPUFF Methodology

The CALPUFF model will be run using the output from the CALMET model and the following input data:

- Source pollutant emission rates and release characteristics
- Background ozone and ammonia concentrations

Several iterations may be performed to simulate various operating conditions, as described previously. Table 5 highlights the CALPUFF model options to be used.

Table 5
CALPUFF Model Options

Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_2, HNO_3 and NO_3
Chemical Transformation	MESOPUFF II scheme with CALPUFF default
Deposition	Wet and Dry
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	PG / MG coefficients
Terrain Effects	Partial plume path adjustment
Output	Create binary file: output species SO_2,SO_4,NO_x, HNO_3 & NO_3
Model Processing	Highest concentration predicted
Background Values	Ozone: 60 ppb[1]; Ammonia: 10 ppb[2]

[1] Maximum indicated for both Eagle Cap and Hells Canyon in the *Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest* (Peterson, et al, 1992)
[2] Value indicated in the Phase 2 Report for grasslands

Visibility

Plume Visual Impairment

Because the Class I areas are greater than 50 kilometers from the source, plume impairment will not be evaluated.

Regional Haze

The regional haze analysis will use the modeled concentration and a postprocessor (CALPOST) to calculate the percent change in extinction attributable to the project emissions as compared to the background extinction, or natural conditions, of Hells Canyon and the Spokane Indian Reservation.

The percent change in light extinction (Δ) will be calculated using:

$$\Delta = \frac{\Delta b}{b_{back}} * 100$$

where Δb is the incremental increase in light extinction due to the project emissions increase and b_{back} is the background light extinction. The incremental increase in light extinction from the project will be given by:

$$\Delta b = 3[\ \delta\chi_{NO3} + \delta\chi_{SO4}]f(RH)$$

where $\delta\chi_{NO3}$ and $\delta\chi_{SO4}$ are the incremental nitrate and sulfate concentrations in $\mu g/m^3$, respectively. Th f(RH) value will be calculated on an hourly basis from hourly relative humidity (RH) data from the CALMET runs, and then averaged for each 24-hour period.

The background extinction, b_{back}, will be calculated using the equation:

$$b_{back} = b_{hygro} \times f(RH) + b_{NonHygro} + Rayleigh$$

where b_{hygro}, $b_{NonHygro}$, and Rayleigh scattering components are provided in the Appendix 2.B of the FLAG Phase I report, for each federal Class I area. Since no value is reported for the Spokane Indian Reservation, the value for Hells Canyon with be used for both areas. Again, f(RH) will be calculated on an hourly basis and averaged for each 24 hour calculation period.

An initial evaluation will use a threshold criteria of a 5% change in light extinction over background levels using 24-hour average impacts from the project emissions increase. If the impact of the project is < 5% for every 24-hour period, no further analysis will be conducted. If the impact is >5%, a cumulative analysis will be performed adding permitted, but not yet operating, industrial sources to the analysis, through consultation with the permitting agency and land manager.

Flora and Water Quality

Impacts to both flora and water quality will be assessed through an analysis of sulfur (as sulfate ion) and nitrogen (as nitrate and ammonium ions) deposition. Annual deposition rates will be determined based on the incremental increase in annual emissions from the proposed project according to methods specified in IWAQM Phase 2 Report..

Annual deposition rates of NOx, HNO_3 and NO_3^- will be calculated by CALPUFF, then converted to nitrogen and summed. Likewise, deposition rates of SO2 and SO_4^{-2} will be converted to sulfur and summed. The CALPOST module will be used to perform the conversion and subsequent summation steps.

The calculated deposition rates (in kg/ha/year) will be compared to the significance levels of 0.1 for nitrogen and 0.06 for sulfur. These values were used in an application for the proposed Sumas 2 Generation Facility (SE2) in Sumas, Washington (EFSEC Application 99-1, 1999). The significance levels represent 2% of the upper level of deposition where no significant injury to soils or aquatic resources would be anticipated, as suggested at the time of that application by the Department of Ecology. It is assumed that the upper level limits for the three Class I areas evaluated in this application would be the same as those identified for the five Class I areas in the SE2 application. Should the impacts from the SPC project be predicted to exceed these levels, further refinements to the analysis will be developed in consultation with the appropriate stakeholders.

Presentation of Results

The results of the air dispersion modeling analyses will be presented as a part of the PSD application. Any deviations from the methodology proposed in this protocol will be presented, along with a summary of the results in tabular and, where appropriate, graphical form. Modeling files used for the ISCST3 analysis will be provided with the application on computer disk. Due to the anticipated size and quantity of data necessary for the CALMET/CALPUFF modeling, this data will be provided electronically upon request.

Caniparoli, Don/PDX

From: Robert Bachman/R6/USDAFS [rbachman@fs.fed.us]
Sent: April 18, 2001 12:19 PM
To: clint@ecy.wa.gov; Caniparoli, Don/PDX; bbur461@ecy.wa.gov; Ken.Richmond@mfgenv.com
Cc: Robert Bachman/R6/USDAFS; allen.philip@deq.state.or.us; hanrahan.patrick.l@deq.state.or.us
Subject: Starbuck modeling protocol etc.

Clint, Don, Bob, Ken

This is a generic comment/request on two issues (ammonia background and the deposition significance criteria) that it would be good if we could get some consistency to in modeling protocols.

In this case I'm responding to both the Starbuck protocol (done by CH2M) and the ARCO Cherry Point modeling for Class I done by MFG (in the ARCO report this might be ok -- I just can't find reference to it in the report). The Starbuck protocol is OK on the ammonia issue, but not on the deposition significance number.

On ammonia: I would like us to assume the ammonia background is relative high "everywhere" -- I'm asking that the IWAQM and other previous guidance that calls for different values over different kind of land use be disregarded. Either use a monitored value, if available, or some conservative number such as 10ppb. The point is there is alot of ammonia out there, much more than previously thought.

On deposition: See the message below from Dee Morse (NPS), particularly the third to last paragraph, about the 2% significance criteria that has been used in some cases. It is the concensus FLM position that number is not sufficiently conservative. The FLM prefers this be a case by case decision based on the existing background estimate at the downwind Class I areas. For modeling significance just recently in Oregon they have used .005 kg/ha/yr for nitrogen and .003 kg/ha/yr for sulfur. This is based on .1% of the 5kg/ha/yr nitrogen and 3kg/ha/yr sulfur concern thresholds.

Hope this is clear -- if not please let's discuss.

Thanks

Bob

----- Forwarded by Robert Bachman/R6/USDAFS on 04/18/01 10:13 AM -----

Dee_Morse@nps
.gov (Dee   To: djmalin@bpa.gov
Morse)   cc: "Robert

Bachman/R6/USDAFS" <rbachman@fs.fed.us>, Tamara_Blett@nps.gov (Tamara Blett)
03/05/01 07:00 AM
Subject: NPS/FS Comments on BPA Regional AQ Modeling Study

Deb,

Both Bob Bachman (US Forest Service) and Tamara Blett (National Park Service) and I have reviewed the deposition section in the January 19, 2001, Bonneville Power Administration Regional Air Quality Modeling Study Protocol and we have the following comments:

Modify footnotes on ?Table 6. Pacific Northwest Class I Areas Background Deposition Fluxes? to read as follows:

Forest Service footnote should read as follows:

Background deposition fluxes for USFS areas were developed using a scientific consensus process in a workshop in 1990. These data are considered to represent a conservative upper limit for these areas -- they are not average values spatially or temporally. The deposition fluxes are reported in table 11 in GTR-299 below. For the Forest Service managed wilderness areas, total background deposition is assumed to be double the high value reported in Table 11 to account for additional dry and occult (cloud and fog water) deposition processes. These flux estimates have not been adjusted since 1990, but are currently considered adequate as guidelines. In all cases decisions based on deposition flux estimates from air quality modeling will consider all pertinent factors, and decisions on acceptable levels will be made by the USDA FS on a case by case basis.

Peterson, J., and et al, 1992: Guidelines for Evaluating Air Pollution Impacts on Class I Areas in the Pacific Northwest. USDA Forest Service, General Technical Report PNW-GTR-299, May 1992.

National Park Service footnote should read as follows:

National Park Service data based on 1995-1997 National Acid Deposition Program annual average deposition values collected at Marblemount, Hoh Ranger

Station, and Pack Forest monitoring sites.

For NPS areas, total background deposition is conservatively assumed to be double the measured wet deposition flux to account for additional dry and occult (cloud water) deposition processes.

We also have a comment concerning the 2% significant criteria for deposition at the National Park Service and Forest Service sites. We do not believe the 2% significant criteria for deposition effects is protective of the resources in National Park Service and Forest Service areas. There is no scientific basis showing that a 2% increase in deposition would not cause an impact to aquatic and/or terrestrial ecosystems. Therefore, we request that the use of the 2% significant criteria not be used. The federal land managers will assess deposition impacts in these areas on a case by case basis.

Please let us know if you have any questions concerning our proposed changes to the Bonneville Power Administration Regional Air Quality Modeling Study Protocol. Please keep us informed of any other developments regarding the proposed modeling protocol.

Also, we have been having problems with our email, if possible please let me know if you receive this message alright.

Thanks,

Dee Morse
Air Resources Division
National Park Service
Phone: 303 969-2817
Fax: 303 969-2822
e-mail: dee_morse@nps.gov

Caniparoli, Don/PDX

From: Clint Bowman [clint@ecy.wa.gov]
Sent: March 30, 2001 11:34 AM
To: Yansura, Mary Beth/SEA
Cc: Caniparoli, Don/PDX
Subject: Starbuck Protocol

Although I usually wait for other comments from my FLM colleagues, I thought I would take this opportunity to put my comments down before they escape me.

First impressions: The quality I've grown accustomed to from you.

Suggested changes:

p4. Receptors - I prefer a more "brute force" approach to capture at least 90 percent of the peaks by using 50 m spacing out to 2000 m, 100 m spacing out to 5 km and (if needed) 500 m spacing out to 15 km.

p10. 2nd paragraph of Flora and Water Quality - don't ignore the NH4+ component of the sulfates and nitrates as it contributes N as well (that's how you can get significant N deposition from a source that has only SO2 emissions.)

p10. 3rd paragraph of Flora and Water Quality - since the FLAG report has now been issued in final form and (as of 1 April 2001) is the guidance to be followed, I'm going to have an increasingly difficult time keeping the FLMs to the agreement (amazing what the passage of two years will do). We'll keep it for Starbuck (you started on it back last fall). The good news is that we had a combined technical and policy meeting yesterday on "cumulative impact analysis" and it looks as if we will be in a position to begin a cumulative impact assessment within three years. If that stays on schedule then I think that NPS and USDA FS will continue to abide by the agreement (I had originally estimated that the agreement would produce the necessary "members of the group" within five years.)

I would guess that any significant impacts of any kind will be sufficient reason to have Starbuck Power Company, LLC to conduct several years of NOX monitoring starting with permit approval (we'd like to have a year, m/l, of pre-operation monitoring as well as a couple of post-operation years.) We need just a single NOx monitor in SE Washington and the costs may very well be shared by one or more other power generators who also are proposing.

Clint
who has been committed to participating in a conference call on

Wednesday next
on the Spokane CO SIP (did I say Kaiser Mead?)

--

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ATTACHMENT C

Building Dimension Information

Table C-1 provides a list of buildings and tanks that were set up with tiers, along with tier numbers and heights.

TABLE C-1
Building Profile Input Program Summary

Name	Description	Building Tiers and Heights
B14S	Air Cooled Condenser South	1 tier, 36.6 m
B14N	Air Cooled Condenser North	1 tier, 36.6 m
Tank18NW	Demin Water Storage Tank North West	1 tier, 12.2 m
Tank18SE	Demin Water Storage Tank South East	1 tier 1, 12.2 m
Tank19SE	Service/Fire Water Storage Tank South East	1 tier, 12.2 m
Bldg1	Combustion Turbine Building	2 tier, 18.3 m, 29.0 m
Bldg5	Control Administration Building	1 tier, 18.3 m
Bldg2	Steam Turbine Building Block	1 tier, 15.2 m
Bldg27	Substation Control Building	1 tier, 6.1 m
Bldg17	Fire Pump Building	1 tier, 6.1m
Bldg21	SCR Ammonia Storage	1 tier, 7.6 m
Bldg6-3	Heat Recovery Steam Generator	1 tier, 27.4 m
Bldg16	Demin Water Transfer Station	1 tier, 6.1 m
Tank19NW	Service/Fire Water Storage Tank	1 tier, 12.2 m
Bldg6-2	Heat Recovery Steam Generator	1 tier, 27.4 m
Bldg6-1	Heat Recovery Steam Generator	1 tier, 27.4 m
Bdg6-4	Heat Recovery Steam Generator	1 tier, 27.4 m

ATTACHMENT D

Class II Modeling Data

Modeling data are summarized in Tables D-1 and D-2. Electronic copies of the data are available upon request.

Table D-1

AIRData – Monitor Values Report

EPA Air Quality Standard:
150 ug/m3 (24-hour average)
50 ug/m3 (annual mean)

Washington Air Quality Monitors for Particulate Matter (All Years)

Counties Selected: Walla Walla

24-Hour Values					# Exceed		Annual							
Row #	**# Obs**	**1st Max**	**2nd Max**	**3rd Max**	**4th Max**	**Actual**	**Est.**	**Mean**	**Year**	**City**	**County**	**State**	**Region**	**Monitor ID**
1	52	49	43	43	43	0	0.0	21.9	1995	Walla Walla	Walla Walla Co	WA	10	530710005-1
2	53	71	70	69	52	0	0.0	26.1	1996	Walla Walla	Walla Walla Co	WA	10	530710005-1
3	59	105	87	72	64	0	0.0	28.8	1997	Walla Walla	Walla Walla Co	WA	10	530710005-1
4	50	54	47	45	44	0	0.0	22.8	1998	Walla Walla	Walla Walla Co	WA	10	530710005-1
5	104	91	69	69	66	0	0.0	23.5	1999	Walla Walla	Walla Walla Co	WA	10	530710005-1
6	103	114	101	99	65	0	0.0	24.3	2000	Walla Walla	Walla Walla Co	WA	10	530710005-1
7	20	45	43	39	30	0	0.0	23.0	2001	Walla Walla	Walla Walla Co	WA	10	530710005-1

TABLE D-2
Summary Results for Criteria Pollutant Analysis

Scenario No.	HRSG Firing	Ambient Temp. (^{o}F)	Evaporative Cooling	Steam Injection	CTG Load Level (%)	Model Results (ug/m^3)					
						Pollutant	**Annual**	**24-Hour**	**8-Hour**	**3-Hour**	**1-Hour**
1	Yes	101	Yes	Yes	100	NO$_X$ as NO$_2$	1.735				
						CO			31.307		122.159
						SO$_X$ as SO$_2$	0.283	1.813		8.896	
						PM	2.008	12.95			
2	No	101	Yes	No	100	NO$_X$ as NO$_2$	1.518				
						CO			31.307		90.111
						SO$_X$ as SO$_2$	0.236	1.507		7.408	
						PM	1.687	10.858			
3	Yes	5101	No	Yes	100	NO$_X$ as NO$_2$	1.774				
						CO			31.307		124.676
						SO$_X$ as SO$_2$	0.290	1.867		9.150	
						PM	1.914	12.393			
4	Yes	51.1	No	Yo	100	NO$_X$ as NO$_2$	1.806				
						CO			31.619		129.747
						SO$_X$ as SO$_2$	0.294	1.880		9.320	
						PM	2.092	13.446			
5	No	51.1	No	Yo	100	NO$_X$ as NO$_2$	1.606				
						CO			31.307		96.128
						SO$_X$ as SO$_2$	0.253			7.980	
						PM	1.717	11.043			
6	Yes	-20	No	Yo	100	NO$_X$ as NO$_2$	1.791				
						CO			31.307		129.809
						SO$_X$ as SO$_2$	0.291	1.899		9.176	
						PM	1.960	12.874			
7	No	-20	No	Yo	100	NO$_X$ as NO$_2$	1.629				
						CO			31.307		100.012

						SO_X as SO_2	0.257	1.672		8.091	
						PM	1.573	10.312			
8	No	-20	No	Yo	85	NO_X as NO_2	1.519				
						CO			31.307		91.18
						SO_X as SO_2	0.236	1.672		8.091	
						PM	1.624	10.513			
9	No	-20	No	No	70	NO_X as NO_2	1.422				
						CO			31.307		82.812
						SO_X as SO_2	0.217	1.377		6.792	
						PM	1.724	11.060			
10	No	51.1	No	No	85	NO_X as NO_2	1.433				
						CO			31.307		83.942
						SO_X as SO_2	0.219	1.396		6.862	
						PM	1.696	10.914			
11	No	51.1	No	No	70	NO_X as NO_2	1.340				
						CO			31.307		82.812
						SO_X as SO_2	0.202	1.257		6.327	
						PM	1.798	11.301			
12	No	101	No	No	85	NO_X as NO_2	1.333				
						CO			31.307		82.812
						SO_X as SO_2	0.202	1.270		6.337	
						PM	1.772	11.236			
13	No	101	No	No	70	NO_X as NO_2	1.256				
						CO			31.307		82.812
						SO_X as SO_2	0.1873	1.180		5.866	
						PM	1.853	11.823			

ATTACHMENT E

Best Available Control Technology Analysis

The Starbuck Power Company's (SPC) Starbuck Power Project (SPP) is subject to the federal prevention of significant deterioration (PSD) rules for particulate matter (PM)—PM less than 10 microns (PM_{10}), nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid (H_2SO_4) mist—and is subject to the new source review requirements provided in 173-400-110 and -113 *Washington Administrative Code* (WAC). Both the PSD regulations and the Washington State new source review (NSR) rules require best available control technology (BACT) to be employed. This attachment presents the BACT analysis for the various emission sources proposed to be installed at the generation plant. These sources are four identical natural gas-fired combustion gas turbines (CGTs), four identical heat recovery steam generators (HRSGs) with supplemental duct firing (duct burners), and a diesel-fuel-fired fire pump.

E.1 Top-Down BACT Methodology

In 40 CFR 52.21(b)(12) [see also 173-400-030(10) WAC], BACT 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 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…

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

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

above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique.”

2. **Eliminate technically infeasible options.** The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific factors. This demonstration should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emission unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

3. **Rank remaining control techniques by control effectiveness.** This ranking should include control efficiencies, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts. If the top control alternative is chosen, then cost and other detailed information in regard to other control options need not be provided.

4. **Evaluate the most effective controls and document results, including a case-by-case consideration of energy, environmental, and economic impacts.** If the top control alternative is selected, impacts of unregulated air pollutants or impacts on other media are considered to determine if the selection of an alternative control option can be justified. If the top control option is not selected as BACT, evaluate the next most effective control option.

5. **Select BACT**, which will be the most effective option not rejected in Step 4.

Steps 1 through 5 have been completed for PM, PM_{10}, NO_X, SO_2, CO, VOC, and H_2SO_4 mist emissions from each emission source that is believed to be subject to the BACT requirements, which begin in Section E.2. The details of how the economic, energy, and environmental impacts were analyzed are presented below.

E.1.1 Economic Impact Analysis

The cost estimation methodology used in this BACT analysis is consistent with the latest EPA guidance (EPA’s *Office of Air Quality Planning and Standards [OAQPS] Control Cost Manual* [EPA 453/b-96-001]). Vendor quotes and engineering estimates are the basis for calculating the total capital and operating costs, or cost differentials, for control options, and they are documented accordingly. Standard engineering economic analysis is used to convert all costs to equivalent annualized costs so that the pollution control cost-effectiveness (in dollars per ton of pollutant controlled) may be calculated for comparison with other control options. The cost estimates include capital costs and annual operation and maintenance costs. Capital costs include both direct costs (equipment purchase costs, sales taxes, freight, installation costs, foundations, supports, field erection, electrical, piping, insulation, and painting) and indirect costs (engineering, construction, contractor fees, startup, performance tests, contingencies, and interest during construction). Annual operation and maintenance costs also include direct and indirect costs. Direct costs include instrumentation, losses in generating revenue, operations and supervision labor, routine replacement parts, maintenance labor, maintenance replacement parts, and contingencies. Indirect costs include overhead, administration, property taxes, and insurance.

The following variables, equations, and assumptions were used to evaluate the cost-effectiveness of alternative control strategies for the pollutants in question:

$$CRF = i(1+i)^n / [(1+i)^n - 1]$$

where,

CRF = capital recovery factor

i = interest rate (assumed at 7 percent)

n = equipment life (assumed 10 years for the equipment and 3 years for the catalyst)

Table E-1 presents the site-specific economic assumptions used in the BACT analysis for all emission sources to be installed at the generation plant. These assumptions include labor rates, estimates of operational and maintenance labor requirements, cost and usage rates of consumables, and indirect costs. The cost-effectiveness of a control technology is calculated by dividing the total annualized costs of the control technology by the potential reduction in pollutant emissions from the application of the control technology.

TABLE E-1
Costing Assumptions

Cost Item	Cost Assumption	Cost
Operator Labor Rate	0.5 Hours/Shift or 1 Hour/Shift	$35.00/Hour
Supervisor Labor Rate	15% of Operating Labor	-
Catalyst Cleaning Labor	80 Hours/Year	$35.00/Hour
Maintenance Material	100% of Maintenance Labor	-
Electricity	NA	$0.035/Kilowatt Hour
Overhead	60% of labor and materials	-
Administrative	2% of Total Capital Investment	-
Property Taxes	1% of Total Capital Investment	-
Insurance	1% of Total Capital Investment	-

E.1.2 Energy Impact Analysis

Two forms of energy impacts that may be associated with a control option for an electrical power generating unit are as follows:

1. An increase in energy consumption resulting from an increased heat input rate may be shown as a reduction of electrical generation resulting from the application of the control technology due to increased parasitic load or back pressure.
2. The reduced unit availability may be due to additional maintenance requirements for the applied control technology.

E.1.3 Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutant being controlled. Increases and decreases in other criteria or non-criteria pollutants may occur with some technologies and also should be identified. Non-air impacts, such as solid waste disposal and increased water consumption, may be an issue as well.

E.2 BACT for NO_X

E.2.1 Theoretical Formation and Control of NO_X

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

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

Reduction of peak temperature or residence time is generally accomplished through (1) injection of water or steam into the high-temperature region of the flame, (2) use of dry, low NO_X (DLN) technology to limit flame temperature and excess oxygen, or (3) use of a catalyst to oxidize the fuel instead of flame combustion. The proprietary XONON™ Cool Combustion technology, a catalytic technology that combusts fuel flamelessly, is currently being developed and marketed by Catalytica Energy Systems (Catalytica).

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

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

E.2.2 Gas Turbine BACT for NO_X

E.2.2.1 Previous BACT Determinations

A database search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) for combined cycle gas turbine (Source Classification Code [SCC] Code 20100201) projects from 1998 to present is summarized in Table E-2. SCR technology is the most stringent control listed in the RBLC. Of the various projects, the most stringent is a 2 parts per million by volume, dry (ppmvd) NO_X (corrected to 15 percent oxygen [O_2]) LAER limit using SCR. The most stringent BACT limit listed is 3.5 ppmvd NO_X (corrected to 15 percent O_2) using SCR.

TABLE E-2
Recent NO_X Limits for Combined Cycle Gas Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
2 ppmv @ 15% O_2	SCR with Ammonia Injection	04/16/1999	PDC El Paso Milford LLC, Connecticut	LAER
2.5 ppm @ 15% O_2	Selective Catalytic Reduction and DLN Burners	12/04/1998	Westbrook Power LLC, Maine	LAER
3.5 ppm @ 15% O_2	Selective Catalytic Reduction	07/13/1998	Casco Ray Energy Co, Maine	BACT
3.5 ppm @ 15% O_2	SCR Ammonia Injection System and Catalytic Reactor	05/01/1998	Rumford Power Associates, Maine	BACT
3.5 ppm @ 15% O_2	SCR	02/13/1998	Tiverton Power Associates, Rhode Island	LAER
3.5 ppm	Ammonia Injection, SCR	03/16/2000	Southern Energy, Inc., Michigan	BACT
4.5 ppm	SCR	02/08/1999	Wyandotte Energy, Michigan	BACT
4 ppmvd	DLN Burner with SCR	06/19/2000	Fort St. Vrain, Colorado	BACT
6 ppm	DLN Burner with SCR	06/29/1998	Bridgeport Energy, LLC, Connecticut	BACT
9 ppmv	DLN Burner	02/13/1998	Air Liquide America Corporation, Louisiana	BACT
9 ppmvd @ 15% O_2	DLN Burner	09/14/1998	Champion International Corp. & Champion Clean Energy, Maine	BACT
9 ppm @ 15% O_2	GE DLN 2.6 Burners	10/15/1999	Duke Energy New Somyrna Beach Power Co. LP, Florida	BACT
9.8 ppmv @ 15% O_2	DLN Burner, Duct Burner On	12/04/1998	Santa Rosa Energy LLC, Florida	BACT

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

E.2.2.2 Technological Feasibility

The Applicant evaluated five different techniques to control NO_X emissions from the combustion turbines. The details for various techniques and their technical feasibility for application to the combustion turbines at the generation plant are described below.

Catalytic Reduction

The primary type of catalytic reduction system for NO_X is SCR, which involves the injection of ammonia into the flue gas stream where it selectively reacts with NO_X in the presence of O_2 and a catalyst to form molecular nitrogen and water. The SCONO$_X$™ system uses a coated catalyst to oxidize and adsorb NO_X (as NO_2) onto the catalyst, but does not actually use the catalyst to reduce the nitrogen compounds. This system is discussed separately below.

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

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

SCR is widely recognized as LAER and BACT for combustion turbines. The maximum NO_X removal efficiency of an SCR system is generally around 80 to 90 percent when initially installed on natural gas-fired units. When used in conjunction with DLN combustion, exhaust gas NO_X concentrations for firing on natural gas generally have been measured around 3.5 ppmvd at 15 percent O_2. Projects have been permitted recently with NO_X emission limitations as low as 2.0 or 2.5 ppmvd. However, the use of SCR can result in secondary PM_{10} [as $2(NH_4(SO_4))$] and ammonia emissions due to the use of ammonia. This technology is considered feasible for use at the generation plant.

SCONO$_X$™

ABB Alstrom Power Environmental Systems (AAP) produces the SCONO$_X$™ system for large combustion turbines under a licensing agreement from Goal Line Environmental Technologies. Unlike SCR, the SCONO$_X$™ system does not use ammonia. Instead, the

$SCONO_X$™ system uses a coated catalyst to oxidize nitrogen oxide (NO) to nitrogen dioxide (NO_2) and to adsorb NO_2 onto the coating on the catalyst. The system consists of a catalyst bed installed in the HRSG at a location where the temperature is between 280°F and 700°F.

The catalyst requires periodic regeneration (up to several times per hour) using a regeneration gas containing 4 percent hydrogen (H_2) , 3 percent nitrogen (N_2), and 1.5 percent carbon dioxide (CO_2). The regeneration gas desorbs the NO_2 from the catalyst, after which it is reduced by hydrogen (in the oxygen-free environment) to N_2. The regeneration gas is created by reacting natural gas with air in the presence of a nickel oxidation catalyst, which is electrically heated to 1,900ºF. This gas is mixed with steam (produced by the HRSG) and passed over a second catalyst to form the regeneration gas. The regeneration gas is introduced into the catalyst rack through a system of piping, valves, and louvers.

The catalyst rack being regenerated must be isolated from the exhaust gases. This is accomplished using two sets of louvers (upstream and downstream of the catalyst module) inside the HRSG. The regeneration gas exits the catalyst rack and is ducted back into the HRSG upstream of the $SCONO_X$™ system. The $SCONO_X$™ louver dampers isolate the catalyst system from the exhaust gases during regeneration. These louver dampers and associated supports are all exposed to the exhaust gas stream, which could present long-term maintenance and reliability problems.

The $SCONO_X$™ system has been demonstrated at the Federal Plant facility in southern California and has been in operation since December 1996. Owned by Sunlaw Cogeneration Partners, this cogeneration generation plant is based on a General Electric (GE) LM-2500 gas turbine. This installation is the second generation of this technology. The first $SCONO_X$™ system was installed on another Sunlaw facility for about 10 months before being taken out of service due to poor regeneration gas distribution. Both the installations (Mods 1 and 2) have experienced numerous outages as a result of failures of the louver system. ABB, as part of its scale-up process, has redesigned the louver system and is testing the redesigned system to determine its function and reliability.

The $SCONO_X$™ system has achieved NO_X emissions of less than 3.5 ppmvd at the Federal Plant in southern California; however, the Federal Plant is only one-tenth the size of one of the combustion turbine units in the proposed generation plant. Goal Line Environmental Technologies has made claims that the $SCONO_X$™ system is capable of achieving emission rates as low as 2.0 ppmvd. However, these claims represent data derived from the Federal Plant in southern California, which is a GE LM-2500-based combustion turbine combined-cycle cogeneration facility (rated at approximately 23 megawatts [MW]), and does not represent emissions from a frame-sized combined-cycle combustion turbine project (nominally rated at 325 MW). The $SCONO_X$™ technology has not been demonstrated on a combustion turbine the size of the combustion turbine units proposed to be installed at the generation plant.

There are many questions surrounding the scale-up and reliability of the $SCONO_X$™ technology. Of primary concern is the regeneration gas distribution across the catalyst. To achieve low NO_X emission levels, proper distribution across the catalyst is critical. The scale-up of the system also will require many mechanical linkages, activators, and damper seals that must operate reliably for the system to remain online. While research and development can be done to reduce the number of moving parts when the system is scaled-up for a larger combustion turbine, the reliability of so many moving parts is a concern. In addition, reliability and useful life of the catalyst beds are a concern. The reactivity of all catalysts degrades over time due to masking or fouling from impurities in the exhaust gases being treated. There is sufficient operating experience with SCR to predict performance and replacement frequency for the catalyst. This type of information is not yet available for SCONO$_X$™. Goal Line Environmental Technologies has indicated that the catalysts will need to be washed once every 6 to 12 months. Washing requires either a major system outage or the purchase of additional catalyst, so that the new catalyst can be used while the old catalyst is washed. The necessity of washing the catalyst affects the operability and reliability of the system.

While there are many concerns surrounding the scale-up and reliability of the SCONO$_X$™ system, EPA Region 1 has notified various states in Region 1 that the SCONO$_X$™ technology should be considered technically feasible for large combustion turbine projects (letter from EPA administrator John DeVillars dated December 20, 1999). EPA Region 9 has issued a letter to Goal Line Environmental Technologies stating "based on our review of the emissions data that you submitted to us, EPA has determined that SCONO$_X$™ has met EPA's criteria as pollution control technology which has been demonstrated in practice." The letter also states that SCONO$_X$™ has demonstrated that it can achieve compliance with a NO$_X$ emission limit of 3.5 ppmvd on a 3-hour rolling average with no ammonia emissions and with extremely low CO emissions. An advantage of the SCONO$_X$™ system is that there is no ammonia use, or ammonia-related emissions, in the process. EPA Region 9 has reviewed additional performance data from the Federal Plant SCONO$_X$™ system and determined that the system was capable of achieving NO$_X$ emissions as low as 2.0 ppmvd on a 3-hour rolling average or 2.5 ppmvd on a 1-hour average. According to the September 1999 California Air Resources Board (CARB) publication *Guidance for Power Plant Siting and Best Available Control Technology*, a NO$_X$ emission concentration of 2.0 ppmvd at 15 percent O_2, as documented with 6 months of continuous emission monitoring (CEM) data, had been achieved at the 32-megawatt (MW) Federal Cold Storage Cogeneration facility in Vernon, California. Other comparable merchant power plants located in California have been permitted with the SCONO$_X$™ technology determined as BACT, provided the technology is commercially available at the time construction procurement contracts are being issued. If the technology is not commercially available, then the projects are required to install SCR.

Additionally, a San Diego Union Tribune newspaper article (January 28, 2000) reported that Pacific Gas and Electric (PG&E) Generating Company has announced that it will install the SCONO$_X$™ system on one of the four combustion turbines at its Otay Mesa Power Project. However, after reviewing the hearing transcripts for the Otay Mesa Power Plant licensing process (through the California Energy Commission), PG&E Generating Company qualifies the January 28, 2000, announcement with the statement that the SCONO$_X$ system will be installed "…if it is able to be commercialized…" (California Energy Commission, Hearing Transcript, November 15, 1999). Additionally, PG&E Generating Company, in concert with AAP, is requesting a 3-year demonstration period for the SCONO$_X$™ system in the air quality permits for the Otay Mesa Power Plant and is incorporating provisions to install a SCR system if the SCONO$_X$™ system fails to meet contractual guarantees (California Energy Commission, Status Conference Transcript, March 2, 2000). Sunlaw also proposes to install the SCONO$_X$™ system on a large combustion turbine at a project yet to be constructed at Nueva Azalea.

Only in the last few months has AAP begun offering performance guarantees for use of SCONO$_X$™ on large combustion turbines. As described above, frequent cycling of the mechanical damper system was the cause of frequent outages of the demonstration project in southern California. AAP's redesigned damper system has been tested only in pilot studies under simulated power plant conditions, and this system has never been tested or installed on an actual gas turbine. Furthermore, the demonstration project described above did not include duct burning.

Use of an unproven emissions control system would represent a major financial risk for the Applicant. While the SCONO$_X$™ system shows potential for large combustion turbine application in the future, its technical feasibility is still questionable at this time. Despite these serious technical concerns, because of the EPA Region 1 position on technical feasibility of the process, SCONO$_X$™ will be included in the technology ranking below.

Post-Combustion NO$_X$ Oxidation

The Cannon low temperature oxidation (LTO) technology was primarily developed to control emissions from steam boilers. The basic operation of the LTO system injects ozone into a cooled exhaust gas (approximately 300°F) to oxidize NO$_X$, CO, and SO$_2$ to nitrates, carbonates, and sulfates. These higher oxides are absorbed by a dilute nitric acid solution in a scrubber. Testing on a natural gas-fired boiler has shown NO$_X$ concentrations below 3.5 ppmvd at 3 percent O$_2$, and vendor literature indicates NO$_X$ guarantees of less than 4 ppmvd.

The LTO system has been demonstrated on relatively small natural gas-fired boilers ranging in size from 4.1 to 16.7 million British thermal units per hour (MMBtu/hr). The volume of exhaust gas from a 16.7 MMBtu/hr boiler will be approximately 145,457 dry standard cubic feet per hour (dscfh). The exhaust gas volume from one of the combustion turbines at the generation plant will be up to 878,195 standard cubic feet per minute (scfm), or 52,691,700 standard cubic feet per hour (scfh) on a wet basis. This will require a drastic scale-up of the LTO technology. Additionally, the scrubber solution will result in the generation of additional pollution (scrubber waste) and will require disposal. Cannon LTO technology literature indicates the scrubber waste can be discharged to sanitary sewer systems, but this option has not been verified and would directly impact costs.

Because it has never been scaled up to the scale required for large combustion turbines, the LTO technology was rejected as a feasible NO$_X$ control measure for the combustion turbines to be installed at the generation plant.

Dry Low-NO$_X$ Combustion Technology

Two types of DLN combustion technology are lean premix combustion and catalytic combustion. Both are described below.

Lean Premix Combustion. The lean premix type is the most popular DLN combustor available. Conventional combustors are diffusion controlled. The fuel and air are injected separately with combustion occurring at the stoichiometric interfaces. This method of combustion results in combustion "hot spots," which produce higher levels of NO$_X$. In the lean premix combustor, the air and fuel are mixed before they enter the combustor. Lean premix combustors have been developed only for gas-fired turbines, and the more advanced designs are capable of achieving a 70 to 90 percent NO$_X$ reduction with NO$_X$

concentrations from 9 to 25 ppmvd. This technology will be incorporated into the combustion turbine design for the CGTs to be installed at the generation plant. Therefore, the lean premix DLN combustion technology is considered technically feasible for the generation plant.

Catalytic Combustion. Another type of DLN combustor on the market is a catalytic combustor, such as Catalytica's XONON™, which uses a catalyst inside the combustor, and the air/fuel mixture passes through the catalyst as combustion occurs at much lower temperatures when compared to a standard combustor. This reduction in the combustion temperature greatly reduces the formation of thermal NO_X. Emissions of NO_X from catalytic combustors are typically below 5 ppmvd. Extensive information about the XONON™ cool combustion technology is available on Catalytica's Web site (www.catalyticaenergy.com). A prototype of the XONON™ combustion system (XONON-1) was installed on a 1.5-MW Kawasaki M1A-13A gas turbine and was operated in a test cell at Tulsa, Oklahoma. During 1,100 operating hours and 220 starts, XONON was proven to reduce NO_X to less than 2.5 parts per million (ppm). A 1.5-MW Kawasaki turbine with XONON-1 then was installed at Silicon Valley Power in late 1998. A commercial-ready XONON-2 equipped on a 1.5-MW turbine began operation at Silicon Valley Power in July 1999; to date, this operation has accumulated more than 7,400 operating hours. Average NO_X emissions at full load have been demonstrated to be less than 2 ppm corrected to 15 percent O_2. However, catalytic combustors have not been applied commercially to gas turbines in the Seimens Westinghouse 501F size range.

Discussions with Catalytica indicate that XONON™ is likely to be commercially available for large combustion turbines by the end of 2002. Currently, the system is commercially available only for smaller combustion turbines. Catalytica has entered a partnership with GE to develop the XONON™ system for the larger combustion turbines. However, Seimens Westinghouse Power Corporation currently is not offering the XONON™ system as an option for the Siemens Westinghouse 501F combustion turbine. Enron, in cooperation with Catalytica and GE, is in the process of commercially demonstrating the XONON™ system on a GE Frame 7FA combustion turbine at a power plant being developed by Enron in Central California (Pastoria District Energy Center). The Pastoria project recently started the siting process in California and is not expected to be operational until the third quarter of 2003. Initial operating results will not be available until early 2004.

The XONON™ system is not commercially available for the Seimens Westinghouse 501F combustion turbine or comparable equipment at this time. Therefore, this technology is not considered feasible for the CGTs to be installed at the generation plant and is eliminated from further consideration in this BACT analysis.

Water/Steam Injection

The injection of water or steam into the combustor of a combustion turbine quenches the flame and absorbs heat, thereby reducing the combustion temperature. This temperature reduction minimizes the formation of thermal NO_X. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, thereby increasing the combustion turbine's maximum power output. The use of water or steam injection reduces NO_X emissions to 25 ppmvd at 15 percent O_2 when firing natural gas, and less than 65 ppmvd when firing on fuel oil. Aeroderivative combustion turbines can accommodate higher water or steam injection rates, achieving NO_X levels to less than 25 ppmvd without any detrimental effects to the combustion turbine components. Industrial gas turbines generally cannot tolerate high injection rates of water or steam. As water injection levels increase, a significant increase in dynamic pressure activity (noise) and engine wear occurs. GE produces a unit that can achieve NO_X levels of 25 ppmvd on gas-fired units and 42 ppmvd on fuel oil-fired units using a "quiet" combustor designed to tolerate higher levels of water without causing excessive dynamic pressure activity. However, GE does not plan to continue development of the quiet combustor.

Most of GE's current combustion turbine designs incorporate DLN combustion technology, which produces lower NO_X emissions, improves efficiency of combined-cycle combustion turbine units, and eliminates problems with turbine vibration caused by flame instability with water/steam injection. Water or steam injection is not expected to enhance NO_X emissions reduction for combustion turbines already equipped with DLN combustion technology. Therefore, while technically feasible, water/steam injection technology will not be considered further in this BACT analysis.

Note that water/steam injection may be used in the combustion turbines at the generation plant for reasons other than controlling NO_X emissions, such as power augmentation and maintaining water balance at the generation plant.

E.2.2.3 Ranking of Remaining Alternatives

Based on previous BACT determinations and technical feasibility discussed above, the following alternatives are advanced for ranking: $SCONO_X$™; SCR; and DLN combustion. These technologies are ranked in Table E-3.

TABLE E-3
NO_X Control Technology Ranking for Combined-Cycle Gas Turbines

Technology	Emission Rate (ppmvd @ 15% O_2, annual average)	Technically Feasible?
$SCONO_X$™ plus DLN Combustion	2.0 to 3.5	Yes[1]
SCR plus DLN Combustion	2.0 to 6.0	Yes
DLN Combustion	9.0 to 25.0	Yes

[1] $SCONO_X$™ recently has become commercially available for large combustion turbines. However, there have not been any full-scale demonstrations on large combustion turbines at this time. Thus, the long-term reliability is still a significant concern.

E.2.2.4 Evaluation of Remaining Alternatives

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

$SCONO_X$™

As described above, the commercial availability and the technical feasibility of $SCONO_X$™ for large combustion turbines is still questionable. However, based on EPA's position in the letter dated December 20, 1999, it is advanced for ranking in this section. The economic, energy, and environmental impacts of the SCONO$_X$™ control technology are discussed below.

SCONO$_X$™ Economic Analysis. In its permit application for the Three Mountain Power Plant (TMPP) project, Three Mountain Power, L.L.C., estimated a cost-effectiveness of $29,470 per ton of NO_X reduction for the PG7241FA turbines. Similarly, in an evaluation submitted to Mr. Matt Haber of EPA Region 9, Elk Hills Power, L.L.C., determined that the cost-effectiveness of SCONO$_X$™ for its project would be $29,621.66 per ton of NO_X reduction, if SCONO$_X$™ were technically feasible for its project.

An estimate of initial capital and catalyst replacement costs for the SCONO$_X$™ system is based on vendor estimates for similar projects. The initial capital costs includes the SCOSO$_X$™ guard bed catalyst system, which is installed upstream of the SCONO$_X$™ system to remove sulfur compounds from the exhaust gas. The guard bed is required to minimize sulfur poisoning of the SCONO$_X$™ catalyst system by sulfur compounds. The capital cost for the SCONO$_X$™ system is about $14 million with a replacement catalyst cost of about $1.9 million every 10 years. Table E-4 shows the cost-effectiveness of the SCONO$_X$™.

SCONO$_X$™ plus DLN combustion, at a cost-effectiveness of $9,838 per ton of NO_X removed, is expected to be more expensive than SCR plus DLN combustion. The cost-effectiveness of $9,838 per ton of NO_X removed appears to be much better than the cost-effectiveness of $29,470 per ton for the TMPP project and $29,621.66 per ton for the Elk Hills Power, L.L.C. project. This variation is likely due to the fact that NO_X emissions after DLN combustion for SPP have been assumed to be equal to 25 ppmvd (corrected to 15 percent O_2), compared to 9 ppmvd (corrected to 15 percent O_2), that may have been assumed for TMPP project and Elk Hills Power, L.L.C. project. This results in a greater amount of NO_X being controlled by SCONO$_X$™ resulting in a better cost-effectiveness. The draft fact sheet prepared by the Washington Department of Ecology (Ecology) for the PSD permit for the Sumas Energy 2 Generation Facility Project also concluded that SCONO$_X$™ was about 2.5 times more expensive than SCR for controlling NO_X emissions and about 2 times more expensive than SCR plus catalytic oxidation for controlling NO_X, CO, and VOC emissions to a comparable level. Because projected NO_X emissions from using either SCONO$_X$™ plus DLN combustion or SCR plus DLN combustion are expected to be similar, the additional cost of SCONO$_X$™ is not warranted and, therefore, is rejected as BACT for the combustion turbines to be installed at the generation plant.

SCONO$_X$™ Energy Impacts. There are energy impacts associated with the use of SCONO$_X$™ technology. The increased back pressure in the combustion turbine that results from adding equipment increases the heat input required to produce power and reduces the peak power output of the combustion turbine. A document looking at the use of CO oxidation catalysts to control hazardous air pollutant (HAP) emissions from combustion turbines includes an estimate of these penalties. This document *Cost Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant Emissions From Stationary Combustion Turbines*, prepared by the Combustion Turbine Work Group of the ICCR, dated September 4, 1998, includes an estimate of the increased heat input rate required to compensate for the pressure drop associated with the catalyst. The work group used a heat input rate increase of 0.105 percent per inch of pressure drop measured in inches of water. The document goes on to say that this is a low estimate and that most turbines would experience a higher increased heat input

TABLE E-4

Combustion Turbine NO_X BACT Analysis $SCONO_X^{TM}$ Reduction from 25 ppmvd to 2.5 ppmvd (corrected)

Cost Item	Cost Factor	Reference	Cost ($)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
Oxidation Catalyst & Auxiliary Equipment	As estimated, A	Vendor Quote	$ 14,000,000
Instrumentation	0.1 x A	(EPA, 1995a)	$ 1,400,000
State Sales Taxes	8.2% x A	WA State Sales Tax	$ 1,148,000
Freight	0.05 x A	(EPA, 1995a)	$ 700,000
PEC Total (B)			**$ 17,248,000**
Direct Installation Costs (DIC)			
Foundation and Supports	0.08 x B	(Ulrich, 1984)	$ 1,379,840
Labor	0.14 x B	(EPA, 1990a)	$ 2,414,720
Electrical	0.04 x B	(EPA, 1990a)	$ 689,920
Additional Duct Work	$6,533 /lf/sf/sf of duct	Peters & Timmerhaus	$ 39,198
Piping	0.02 x B	(EPA, 1995a)	$ 344,960
Insulation	0.01 x B	(EPA, 1995a)	$ 172,480
Painting	0.01 x B	(EPA, 1990a)	$ 172,480
DIC Total			**$ 5,213,598**
Total DC = PEC + DIC			**$ 22,461,598**
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	$ 1,724,800
Construction Overhead	0.05 x B	(EPA, 1990a)	$ 862,400
Contractor Fees	0.1 x B	(EPA, 1990a)	$ 1,724,800
Startup	0.02 x B	(EPA, 1990a)	$ 344,960
Performance Testing	0.01 x B	(EPA, 1990a)	$ 172,480
Contingencies	0.03 x B	(EPA, 1990a)	$ 517,440
Simple Interest During Construction	7% x B x 0.5 years	Estimate	$ 603,680
Total IC			$ 5,950,560
Total Capital Investment (TCI) = DC + IC			**$ 28,412,158**

TABLE E-4

Combustion Turbine NO$_X$ BACT Analysis SCONO$_X$™ Reduction from 25 ppmvd to 2.5 ppmvd (corrected)

Cost Item	Cost Factor	Reference	Cost ($)
Annual Costs			
Operating Cost Factors for the Oxidation Catalyst			
Cost Data			
Interest Rate	7.0%	Capital Recovery Factor (CRF)	
Catalyst Life	10	0.142	
Equipment Life	10	0.142	
Direct Annual Costs, $/Year			**Cost ($)/Year**
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 3.9 inch WG of pressure drop, $0.035/kWh @ 8680 hrs/yr @ avg 162,500 kW	Vendor	$ 269,547
Operating Labor	$35/hr @ 1 hr/12 hr shift, 2 shifts per day	Industry Average/Estimate	$ 25,550
Supervisory Labor	15% of Operating Labor	(EPA, 1993a)	$ 3,833
Maintenance Labor and Materials		Vendor	$ 331,400
Steam and Natural Gas		Vendor	$ 406,400
Catalyst Cleaning	80 man-hours per year @ $35/hr	Estimate	$ 2,800
Revenue Loss during Catalyst Replacement (a)	72 hours @ $0.035/kWh and 325,000 kW	Estimate	$ 819,000
Catalyst Replacement Labor (b)	8 workers for 40 hours @ $35/hr every 10 years	Estimate	$ 11,200
Catalyst Replacement (CR) (c)	$1,900,000 every 10 years Inc. Disposal	Vendor Quote	$ 1,900,000
Sales Tax (d)	8.2%	WA Sales Tax	$ 155,800
Sum of a, b, c, and d			**$ 2,886,000**
Capital Recovery	(a + b + c + d) * CRF	(EPA, 1995a)	$ 410,901
Total Direct Annual Costs, $/Year			**$ 1,450,431**
Indirect Annual Costs, $/Year			
Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	$ 216,470
Insurance and Administration	3% of TCI	(EPA, 1990a)	$ 852,365
Capital Recovery	CRF x (TCI - initial catalyst charge)	N/A	$ 3,752,552
Property Tax	1% of TCI	Estimate	$ 284,122
Total Indirect Annual Costs, $/Year			**$ 5,105,508**
Total Annual Costs, $/Year			**$ 6,555,939**
Total Net NOx Reductions (TPY)			**$ 666**
Cost-Effectiveness, $/ton			**$ 9,838**

kWh = kilowatt hour
WG = water gauge
N/A = not available

SCONO$_X$^{TM} Environmental Considerations. The SCONO$_X$™ system does not use ammonia as a reactant, but uses a regeneration gas that is generated from reacting natural gas and steam. Therefore, the SCONO$_X$™ system does not emit unreacted ammonia. However, the SCONO$_X$™ catalyst system does require frequent washing as part of the regeneration process. These washings will result in significant additional water requirements for the generation plant and will generate wastewater. This wastewater could be considered hazardous due to the trace metals in the catalyst substrate.

SCR

SCR is a proven technology on Siemens Westinghouse 501F combustion turbines and has been successfully employed in controlling NO$_X$ emissions from all sizes of combustion turbines. As NO$_X$ emission rates have dropped, the level of sophistication has increased in terms of the ammonia injection system and process controls.

The catalyst must be at an optimum operating temperature (570°F to 750°F) for the SCR system to operate successfully, which is not the case when the combustion turbines are in startup mode. During startup, the SCR is not operational until the catalyst surface reaches the nominal operating temperature (570°F) due to decreased catalyst activity at lower temperatures and limitations on the amount of ammonia that can be emitted. The DLN combustors are operational during startup of the combustion turbines.

The economic, energy, and environmental impacts of the SCR control technology are discussed below.

SCR Economic Analysis. Because SCR is considered to be the most effective control option after SCONO$_X$™, and the Applicant has decided that it will install SCR for controlling NO$_X$ emissions from the combustion turbines, an economic analysis is not required as per the top-down methodology. However, based on the information provided in the draft fact sheet prepared by Ecology for the PSD permit for the Sumas Energy 2 Generation Facility Project, use of SCR for NO$_x$ control costs approximately 40 percent of what it would cost using SCONO$_x$™.

SCR Energy Impacts. Use of the SCR system does create significant additional pressure drop in the combustion turbine exhaust (see Section E.1.2). The pressure drop anticipated for the proposed SCR system is not considered excessive, but has been factored into the economic impact of the technology. EPA's *Alternative Control Techniques Document – NO$_X$ Emissions from Stationary Gas Turbines,* January 1993 (ACT Document), indicates that additional operational energy requirements for SCR are small; however, there are peak power output and fuel penalties. EPA estimates the power output penalty at about 0.5 percent.

SCR Environmental Considerations. A concern associated with SCR technology is the effect of sulfur-bearing fuels on the catalyst. The other problems associated with the use of sulfur-bearing fuels are due to the formation of ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$). These are ammonia salts formed by the chemical reaction between the sulfur in the fuel (emitted as sulfur oxides in the exhaust gas) and ammonia injected for NO$_X$ control and are emitted to the atmosphere as PM.

Ammonium bisulfate is a sticky substance that forms in the lower temperature section of the HRSG where it deposits on the walls and heat transfer surfaces. These surface deposits result in increased pressure drop, reduced heat transfer and power output, and lower cycle efficiency. To prevent corrosion damage, the HRSG must be shut down periodically and water-washed, thereby reducing availability. While ammonium sulfate is not corrosive, its formation also contributes to plugging and fouling of the heat transfer system, leading to reduced heat transfer efficiency and higher PM emissions. Low-sulfur fuel (natural gas) will be the only fuel used for combustion at the generation plant; therefore, this problem is expected to be minimized.

Also of concern is the handling and use of ammonia. Ammonia use in the SCR process for NO_X control presents the potential for environmental impacts. Ammonia is regulated under the EPA Risk Management Program (RMP) (unless the concentration used is under the regulated concentration of 20 percent) and Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur in several ways, including ammonia slip, and accidental release during transport, transfer, or storage. In addition, ammonia is potentially a PM_{10} precursor and is a significant contributor to regional secondary PM formation and visibility degradation. Concerns about the potential health impacts of secondary emissions, such as nitrous oxide and nitroamines, have also been raised (Schorr, 1991). For this project, however, dispersion modeling indicates that ammonia emissions would be well below the acceptable source impact level used to demonstrate under the Washington air toxic rules that emissions from the source are sufficiently low to protect human health and safety (176-460-07 WAC).

Ammonia slip results because it is impossible to provide perfect mixing or an infinite residence time for chemical reaction between the ammonia and the nitrogen oxides. Theoretically, given perfect conditions, the stoichiometric amount of ammonia could be added, resulting in complete reaction of all NO_X and all ammonia molecules. In reality, because of imperfect conditions and variable turbine operating conditions, a stoichiometric excess of ammonia must be added to meet target NO_X emissions. This stoichiometric excess is emitted from the stack as ammonia slip.

Thus, there is an approximate inverse relationship between effluent NO_X and ammonia concentrations. The only practical way to reduce ammonia slip is to increase the effluent NO_X. If ammonia emissions are to be lower than 10 ppmvd at 15 percent O_2, NO_x emissions will have to be higher than 2.5 ppmvd at 15 percent O_2.

The other environmental impact associated with SCR is disposal of the spent catalyst. The catalysts used in SCR systems must be replaced every 2 to 3 years. These catalysts contain heavy metals, including vanadium pentoxide, which is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when disposing of the spent catalyst.

Proposed SCR Operational Conditions. For the generation plant, NO_X can be limited to 2.5 ppmvd (corrected to 15 percent O_2), based on a 24-hour averaging period, at a 10 ppmvd (corrected to 15 percent O_2) slip of ammonia based on a 24-hour averaging period.

The ability to achieve a 2.5 ppmvd (corrected) NO_X effluent is dependent on achieving a 25 ppmvd (corrected) effluent from the turbine DLN combustors. In reality, the turbine manufacturer will guarantee this limit only on a time-average basis. Actual turbine exhaust concentrations are subject to fluctuations due to changing load and ambient meteorological conditions. The Siemens Westinghouse turbine DLN combustors are state of the art. Lower

NO_X emission rates may be commercially available, but come at an increased cost. If the generation plant proposes DLN only as the BACT, then it likely will have installed DLN combustors with a lower NO_X exhaust concentration. Thus, it is impossible to meet a 2.5 ppmvd (corrected) limit on an instantaneous basis. Use of shorter averaging periods will require a higher NO_X limit.

It should be noted that during periods of duct burning, a significant percentage of the total mass flow of NO_X to the SCR system is contributed by the duct burners. For the generation plant, the total mixed exhaust from the combustion turbines plus the duct burners will be limited to 2.5 ppmvd (corrected).

The 10 ppmvd ammonia slip is necessary to meet the proposed 2.5 ppmvd (corrected) NO_X effluent concentration. Lower slip levels could seriously compromise the ability to achieve the specified NO_X emission rate. During the design life of the SCR catalyst, "poisoning" occurs due to sulfur and other compounds, thus reducing the activity of the catalyst and increasing ammonia slip. Use of a 10 ppmvd ammonia slip limit will allow efficient SCR operation during the entire design life of the system.

DLN Combustion

Evaluation of the economic, energy, and environmental impacts of DLN combustion control technology is not required as per the top-down methodology because the Applicant has already selected SCR plus DLN combustion as the BACT for NO_X emissions from the combustion turbines. DLN combustors are the standard on current Siemens Westinghouse large-frame turbines, and no adverse energy or environmental impacts have been attributed to DLN combustion.

E.2.2.5 Combustion Turbine NO_X BACT Summary

The available NO_X control methods with the highest control efficiencies are catalytic chemical reduction of NO_X after it is formed in the combustor, and prevention of NO_X formation through the use of DLN combustors. Both DLN combustors and catalytic reduction will be used at the generation plant.

There continues to be significant debate and concern about the commercial availability and technical feasibility of the $SCONO_X$™ catalytic reduction system for large gas turbines. This technology is not a proven technology in operations of a turbine of this size and is not technically feasible. In addition, it is not economically feasible for the generation plant.

Therefore, SCR plus DLN combustion at 2.5 ppmvd (corrected to 15 percent O_2), based on a 24-hour averaging basis, with 10 ppmvd ammonia slip (corrected to 15 percent O_2) based on a 24-hour average basis, is proposed as BACT.

E.2.3 HRSG Duct Burner BACT for NO_X

The HRSGs transfer heat from combustion turbine exhaust gases to feed water and steam to produce super-heated steam for the steam turbine. The function of the duct burners located in each of the HRSGs is to augment power production by increasing exhaust gas flows and temperatures.

Available technologies for control of NO_X emissions from duct burners associated with the HRSGs are comparable to those for control of NO_X emissions from combustion turbines. $SCONO_X$™, SCR, and DLN combustion technology are applicable and available.

Duct burners fire fuel into the exhaust from combustion turbines. The extra fuel consumes only oxygen present in the combustion turbine exhaust with no addition of extra air. Thus, apart from the use of low NO_X burners, it is impossible to control a duct burner using an add-on control device separately from the combustion turbine.

The cost-effectiveness evaluation for $SCONO_X$™ presented for the combustion turbines considers the NO_X contribution of both the combustion turbines and duct burners. Because the technology has not been acceptable for controlling NO_X emissions from the combination of combustion turbine plus duct burner, it will not be acceptable for controlling the NO_X emissions from the duct burner alone.

SCR plus DLN combustion represents the next most stringent control available for the duct burners. Thus, the same control limits that apply to the combustion turbines also would apply to the duct burners.

Because the balance of the BACT analysis for HRSG duct burners is identical to that for the combustion turbines, it has not been repeated in this section.

E.3 BACT for CO

E.3.1 Theoretical Formation and Control of CO

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

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

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

E.3.2 Gas Turbine BACT for CO

E.3.2.1 Previous BACT Determinations

Table E-5 summarizes the database search of EPA's RBLC for recent combined-cycle gas turbine (SCC Code 20100201) projects from 1998 to present. Catalytic oxidation is the most stringent control listed in the RBLC. Of the catalytic oxidation projects, the most stringent is a 3 ppm CO LAER limit. The most stringent BACT limit listed is 9 ppmvd (corrected to 15 percent O_2). The averaging period has not been specified for these limits.

TABLE E-5
Recent CO Limits for Combined-Cycle Gas Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
3 ppm	Catalytic Oxidizer	02/08/1999	Wyandotte Energy, Michigan	LAER
9 ppmvd	Good Combustion Practices	06/19/2000	Fort St. Vrain, Colorado	BACT
9 ppmvd @ 15% O_2	No Controls	09/14/1998	Champion International Corp. and Champion Clean Energy, Maine	BACT
10 ppm Gas and Oil	Pre-Mix Fuel Air to Optimize Efficiency	06/29/1998	Bridgeport Energy, L.L.C., Connecticut	BACT
10 ppmv @ 15% O_2	Oxidation Catalyst	04/16/1999	PDC El Paso Milford L.L.C., Connecticut	BACT
12 ppm	Good Combustion	10/15/1999	Duke Energy New Somyrna Beach Power Co., L.P., Florida	BACT
12 ppm @ 15% O_2	Good Combustion	02/13/1998	Tiverton Power Associates, Rhode Island	BACT
15 ppm @ 15% O_2	Pollution Prevention Using 15% Excess Air	12/04/1998	Westbrook Power L.L.C., Maine	BACT
15 ppm @ 15% O_2	Pollution Prevention, Good Combustion Control	05/01/1998	Rumford Power Associates, Maine	BACT
20 ppm @ 15% O_2	Pollution Prevention Using 15% Excess Air	07/13/1998	Casco Ray Energy Company, Maine	BACT
25 ppm	Good Equipment Design, Proper Combustion Technique and Minimum 2% Excess Air	02/13/1998	Air Liquide America Corporation, Louisiana	BACT

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

E.3.2.2 Technological Feasibility

The Applicant evaluated three different techniques for the control of CO emissions from the combustion turbines. The details for various techniques and their technical feasibility in applying them to the combustion turbines at the generation plant are described below.

Catalytic Oxidation

The SCONO$_X$™ catalyst will oxidize CO to CO_2 in addition to oxidizing NO to NO_2 (before subsequent adsorption and reduction to N_2). Based on discussions with AAP, reduction of CO to about 3 ppmvd (corrected to 15 percent O_2) is achievable with a SCONO$_X$™ system designed to reduce NO_X from 25 ppmvd to 2.5 ppmvd (corrected to 15 percent O_2). As described above, SCONO$_X$™ has never been operated in practice on large combustion turbines, and serious questions exist regarding its commercial availability for the type and size of combustion turbines to be installed at the generation plant.

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

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

Catalytic Combustion

The XONON™ system, manufactured by Catalytica, shows promise in future applications for simultaneously reducing NO_X, CO, and VOC emissions. As discussed in the BACT for NO_X section of this document, the XONON™ system is not currently available for large combustion turbines such as the Siemens Westinghouse 501F. This technology is not commercially available and, thus, is not technically feasible for the generation plant.

Efficient Combustion

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

E.3.2.3 Ranking of Remaining Alternatives

The remaining alternatives are catalytic oxidation and good combustor design. Table E-6 shows a ranking of these technologies.

TABLE E-6
CO Control Technology Ranking for Combustion Turbines

Technology	Emission Rate (ppmvd @ 15% O_2)	Technically Feasible?
Catalytic Oxidation plus Good Combustor Design	3 – 10	Yes
Good Combustor Design	9 – 25	Yes

E.3.2.4 Evaluation of Remaining Alternatives

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

Catalytic Oxidation

The economic, energy, and environmental impacts associated with the use of catalytic oxidation control techniques are discussed below.

Catalytic Oxidation Economic Analysis. The capital, operations, and maintenance costs of $SCONO_X$™ are significantly higher than the comparable costs for traditional catalytic oxidation systems. Therefore, plotting the least-cost envelope as suggested in the *Draft New Source Review Workshop Manual* shows $SCONO_X$™ to be an inferior control for CO control in instances where the same system would not be used for NO_X control. Thus $SCONO_X$™ is rejected as the BACT for CO at the generation plant.

Based on vendor estimates (obtained from Engelhard) for similar projects, basic oxidation catalyst equipment costs of $662,000 for a system capable of reducing CO emissions from 20 ppmvd to 4 ppmvd (corrected to 15 percent O_2), which includes the catalyst modules, internal frame, and internal seals, were used. The remainder of the cost analysis was based on accepted engineering and economic principles. Annual capital and operating costs for the installation and operation of the oxidation catalyst system for one combustion turbine were calculated using EPA *Control Cost Manual*[1] methodology. These costs include operating and maintenance labor, supervision labor, material costs, catalyst cleaning and replacement costs (both labor and expenses), and capital recovery for both the initial equipment purchase and periodic catalyst replacement costs.

The most cost-effective installation of the oxidation catalyst equipment (including the catalyst module, auxiliary equipment, instrumentation, catalyst, and structural supports) results in an estimated total annual cost of $958,603 per turbine and will reduce the combustion turbine CO emissions by 299 tons per year per turbine. The cost-effectiveness of this system is $3,210/ton CO removed. Table E-7 presents the economic analysis for the installation of an oxidation catalyst to control CO emissions.

Ecology has not identified a cost-effectiveness threshold for the installation of an oxidation catalyst system on a combined-cycle combustion turbine project. Whether $3,210/ton CO removed is considered cost-effective, the Applicant has decided to install the oxidation catalyst for controlling CO emissions. The Applicant requests a limit of 4.7 ppmvd corrected to 15 percent O_2 on an 8-hour rolling average basis, either with or without the duct burner being in operation.

Catalytic Oxidation System Energy Impacts. As with other add-on control devices, energy impacts are associated with the use of oxidation catalysts. A peak power output penalty and a fuel penalty are associated with use of the oxidation catalyst. Use of the catalytic oxidation system creates additional pressure drop in the combustion turbine exhaust. Typical losses are 1.5 to 3.0 inches of water. As described above, this can result in (1) an increase in energy consumption resulting from an increased heat rate, which may be shown as a reduction of electrical generation resulting from the application of the control technology due to increased parasitic load or back pressure, and (2) the reduced unit availability, which may be due to additional maintenance requirements for the applied control technology. The pressure drop anticipated for a catalytic oxidation system is not considered excessive, but was included in the economic analysis. As previously discussed, the ICCR document, *Cost Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant Emissions from Stationary Combustion Turbines*, which examines the use of oxidation catalysts to control HAP emissions from combustion turbines, also includes an estimate of associated energy penalties. For heavy-frame turbines, the document cites a rule-of-thumb heat rate penalty estimate of 0.15 percent penalty per inch of pressure drop. A power output penalty of 0.15 percent per inch of pressure drop also is presented.

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[1] USEPA, *Control Cost Manual*, 4th Edition, January 1990. EPA 450/3-90-006.

TABLE E-7
Combustion Turbine CO BACT Analysis Oxidation Catalyst Reduction from 20 ppmvd to 4 ppmvd (corrected)

Cost Item	Cost Factor	Reference	Cost ($)
Direct Costs (DC)			
Purchased Equipment Costs (PEC)			
Oxidation Catalyst & Auxiliary Equipment	As estimated, A	Vendor Quote	$ 662,000
Instrumentation	0.1 x A	(EPA, 1995a)	$ 66,200
State Sales Taxes	8.2% x A	WA State Sales Tax	$ 54,284
Freight	0.05 x A	(EPA, 1995a)	$ 33,100
PEC Total (B)			**$ 815,584**
Direct Installation Costs (DIC)			
Foundation and Supports	0.08 x B	(Ulrich, 1984)	$ 65,247
Labor	0.14 x B	(EPA, 1990a)	$ 114,182
Electrical	0.04 x B	(EPA, 1990a)	$ 32,623
Additional Duct Work	$6,533 /lf/sf/sf of duct	Peters & Timmerhaus	$ 19,599
Piping	0.02 x B	(EPA, 1995a)	$ 16,312
Insulation	0.01 x B	(EPA, 1995a)	$ 8,156
Painting	0.01 x B	(EPA, 1990a)	$ 8,156
DIC Total			**$ 264,274**
Total DC = PEC + DIC			**$ 1,079,858**
Indirect Costs (IC)			
Engineering	0.1 x B	(EPA, 1990a)	$ 81,558
Construction Overhead	0.05 x B	(EPA, 1990a)	$ 40,779
Contractor Fees	0.1 x B	(EPA, 1990a)	$ 81.558
Startup	0.02 x B	(EPA, 1990a)	$ 16,312
Performance Testing	0.01 x B	(EPA, 1990a)	$ 8,156
Contingencies	0.03 x B	(EPA, 1990a)	$ 24,468
Simple Interest During Construction	7% x B x 0.5 years	Estimate	$ 28,545
Total IC			**$ 281,376**
Total Capital Investment (TCI) = DC + IC			**$ 1,361,235**

TABLE E-7
Combustion Turbine CO BACT Analysis Oxidation Catalyst Reduction from 20 ppmvd to 4 ppmvd (corrected)

Cost Item	Cost Factor	Reference	Cost ($)
Annual Costs			
Operating Cost Factors for the Oxidation Catalyst			
Cost Data			
Interest Rate	7.0%	Capital Recovery Factor (CRF)	
Catalyst Life	10	0.142	
Equipment Life	10	0.142	
Direct Annual Costs, $/Year			**Cost ($)/Year**
Power Loss due to Pressure Drop across Catalyst	0.14% per inch @ 3.9 inch WG of pressure drop, $0.035/kwh @ 8680 hrs/yr @ avg 162,500 kW	Vendor	$ 207,344
Operating Labor	$35/hr @ 1 hr/12 hr shift, 2 shifts per day	Industry Average/Estimate	$ 12,775
Supervisory Labor	15% of Operating Labor	(EPA, 1993a)	$ 1,916
Maintenance Labor and Materials		Vendor	$ 12,775
Steam and Natural Gas		Vendor	$ 12,775
Catalyst Cleaning	80 man-hours per year @ $35/hr	Estimate	$ 2,800
Revenue Loss during Catalyst Replacement (a)	72 hours @ $0.035/kwh and 325,000 kW	Estimate	$ 750,960
Catalyst Replacement Labor (b)	8 workers for 40 hours @ $35/hr every 10 years	Estimate	$ 11,200
Catalyst Replacement (CR) (c)	$1,900,000 every 10 years Inc. Disposal	Vendor Quote	$ 563,000
Sales Tax (d)	8.2%	WA Sales Tax	$ 46,166
Sum of a, b, c, and d			**$1,371,326**
Capital Recovery	(a + b + c + d) * CRF	(EPA, 1995a)	$ 522,546
Total Direct Annual Costs, $/Year			**$ 772,931**
Indirect Annual Costs, $/Year			
Overhead	60% of sum of all labor costs + maintenance materials	(EPA, 1990a)	$ 24,145
Insurance and Administration	3% of TCI	(EPA, 1990a)	$ 40,837
Capital Recovery	CRF x (TCI - initial catalyst charge)	N/A	$ 107,078
Property Tax	1% of TCI	Estimate	$ 13,612
Total Indirect Annual Costs, $/Year			**$ 185,672**
Total Annual Costs, $/Year			**$ 958,603**
Total Net NOx Reductions (TPY)			**$ 299**
Cost Effectiveness, $/ton			**$ 3,210**

Environmental Impacts of Combustion Turbine Catalytic Oxidation. The primary environmental impact associated with the use of an oxidation catalyst is an increase in PM_{10} emissions due to the additional oxidation of sulfur and ammonia present in the combustion turbine exhaust gas. The combustion turbine oxidizes any sulfur compounds in the natural gas (either naturally occurring or added as an odorant) to SO_2. The SO_2 would be further oxidized to SO_3 across the oxidation catalyst and would be emitted as a sulfate, which is considered PM. Additionally, the oxidation catalyst may oxidize unreacted ammonia (from the SCR) to form PM_{10}.

Disposal of the spent catalysts could represent an environmental impact. The catalysts used must be replaced about every 3 to 6 years. The catalyst contains heavy metals that may cause the spent catalyst to be considered a hazardous waste. However, catalyst vendors typically accept return of spent catalysts for recovery and reuse of the catalysts' precious metals.

Summary of Catalytic Oxidation. Catalytic oxidation presents secondary environmental considerations, including increased pressure drop, which lowers plant fuel efficiency, and increased PM emissions. However, despite its high cost and secondary environmental considerations, catalytic oxidation will be used as the BACT for control of CO emissions from the combustion turbines at the generation plant.

Good Combustor Design

The generation plant will use state of the art combustor design to minimize CO emissions before they are controlled further using catalytic oxidation. Because the Applicant has selected catalytic oxidation as the BACT for CO emissions from combustion turbines, an evaluation of the economic, energy, and environmental impacts of good combustor design is not necessary as per the top-down methodology. In any case, no adverse energy or environmental impacts can be attributed to good combustor design.

E.3.2.5 Combustion Turbine CO BACT Summary

The available methods for control of CO emissions from the combustion turbines are good combustor design and catalytic oxidation. Both methods will be used at the generation plant.

Good combustor design and catalytic oxidation at 4.7 ppmvd (corrected to 15 percent O_2), based on an 8-hour rolling average basis, are proposed as BACT, either with or without the duct burner being in operation.

E.3.3 HRSG Duct Burner BACT for CO

As previously described, duct burners fire fuel into the exhaust from combustion turbines. The extra fuel consumes only oxygen present in the turbine exhaust with no addition of extra air. Thus, it is impossible to control a duct burner using an add-on control device separately from the combustion turbine.

The cost-effectiveness evaluation for catalytic oxidation presented for the combustion turbines considers the CO contribution of both the combustion turbines and duct burners. Good combustor design along with catalytic oxidation will be used to control the CO emissions from the combustion turbines plus the duct burners. Thus, the control limits will apply to the combustion turbines together with the duct burners.

Because the balance of the BACT analysis for HRSG duct burners is identical to that for the combustion turbines, it has not been repeated in this section.

E.4 BACT for VOCs

E.4.1 Theoretical Formation and Control of VOCs

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

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

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

E.4.2 Combustion Turbine BACT for VOC

E.4.2.1 Previous BACT Determinations

Table E-8 summarizes a database search of EPA's RBLC for recent combined-cycle gas turbine (SCC Code 20100201) projects from 1998 to present. Good or efficient combustion, low NO_X burner, and no controls are the various types of control technologies listed in the database. Because the emission limits are in different units, it is difficult to compare and determine which emission limit represents the most stringent control.

E.4.2.2 Technological Feasibility

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

E.4.2.3 Ranking and Evaluation of Remaining Alternatives

Catalytic oxidation system costs, energy impacts, and environmental impacts were previously reviewed and discussed under the BACT for CO section. Use of catalytic oxidation

TABLE E-8
Recent VOC Limits for Combined-Cycle Gas Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
0.016 lb/MMBtu	Efficient Combustion	03/16/1999	Alabama Power Company—Theodore Cogeneration, Alabama	BACT
0.4 ppm @ 15% O_2	No Controls	12/04/1998	Westbrook Power L.L.C., Maine	BACT
1 ppm	Low NO_x Burner	07/13/1998	Casco Ray Energy Company, Maine	BACT
2 ppm @ 15% O_2	Good Combustion	02/13/1998	Tiverton Power Associates, Rhode Island	BACT
3 lb/h Gas	No Controls	09/14/1998	Champion International Corp. and Champion Clean Energy, Maine	BACT
3 lb/h Natural Gas	Combustion Controls	04/16/1999	PDC El Paso Milford L.L.C., Connecticut	BACT

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

would consume extra fuel in the generation plant and would create additional PM emissions.

Assuming that the same catalytic oxidizer as designed for CO control would be used for VOC control, then total annual costs would be $958,603 per combustion turbine, as detailed in the BACT for CO section of this document. Accurate estimates for reduction in VOC emissions due to catalytic oxidation are not available for the generation plant. However, based on estimates for similar projects, the catalytic oxidizer could reduce VOC emissions by up to 5 tons per year per turbine, including duct burner emissions. Thus, catalytic oxidation cost-effectiveness for VOC reduction would be $191,721 per ton. Because the Applicant has decided that it will use catalytic oxidation to control CO emissions, the high cost per ton of VOC emissions reduction is immaterial.

The combustion turbines at the generation plant will use state-of-the-art combustor design to minimize VOC emissions before they are further controlled using catalytic oxidation.

E.4.2.4 Summary

Combustion turbine VOC emissions are created through the same mechanisms as CO emissions. Catalytic oxidation is a technically feasible method of controlling VOC emissions, but is clearly not cost-effective if the purpose was to control just the VOC emissions. The next most stringent VOC control technique is good combustor design. The Applicant has selected catalytic oxidation for controlling CO emissions. That along with good combustor design is selected as the BACT for controlling VOC emissions from combustion turbines at the generation plant. A VOC emission limit of 3.5 ppmvd corrected to 15 percent O_2 on a 24-hour average basis, either with or without the duct burner being in operation, is proposed as BACT for the combustion turbines.

E.4.3 HRSG Duct Burner BACT for VOC

As previously described, duct burners fire fuel into the exhaust from combustion turbines. The extra fuel consumes only oxygen present in the turbine exhaust with no addition of extra air. Thus it is impossible to control a duct burner using an add-on control device separately from the combustion turbine.

The cost-effectiveness evaluation for catalytic oxidation presented for the combustion turbines considers the VOC contribution of both the combustion turbines and duct burners.

Good combustor design along with catalytic oxidation will be used to control the VOC emissions from the combustion turbines plus the duct burners. Thus the control limits will apply to the combustion turbines together with the duct burners.

Because the balance of the BACT analysis for HRSG duct burners is identical to that for the combustion turbines, it has not been repeated in this section.

E.5 BACT for PM and PM_{10}

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

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

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

E.5.2.1 Previous BACT Determinations

Table E-9 summarizes a database search of EPA's RBLC database for recent combined-cycle gas turbine (SCC Code 20100201) projects from 1998 to present. Generally, there are no controls listed for controlling PM emissions from combustion turbines, except for good combustion and use of natural gas as the fuel. The most stringent BACT limit listed is 0.0089 lb/MMBtu of PM_{10}.

E.5.2.2 Technical Feasibility and Ranking of Remaining Alternatives

As mentioned above, little can be done to limit PM emissions from natural gas combustion. In AP-42 Section 3.1, EPA acknowledges that "PM emissions are negligible with natural gas firing…". The new source performance standards require no PM controls for gas turbines.

Turbine manufacturers' guarantees of PM emissions are highly variable and depend on the anticipated natural gas quality, ambient dust concentrations, quality of water used for inlet air chillers (which increase the power plant efficiency, thus reducing emissions of other

TABLE E-9
Recent PM and PM_{10} Limits for Combined-Cycle Gas Turbine Projects

Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
0.0089 lb/MMBtu (PM_{10})	Good Combustion	02/13/1998	Tiverton Power Associates, Rhode Island	BACT
0.011 lb/MMBtu Nat Gas (PM_{10})	Natural Gas as Primary Fuel, Low Sulfur (0.5%W) Oil as Backup	04/16/1999	PDC El Paso Milford L.L.C., Connecticut	BACT
0.012 lb/MMBtu (PM)	Combustion of Natural Gas Only	03/16/1999	Alabama Power Plant Company—Theodore Cogeneration, Alabama	BACT
0.06 lb/MMBtu (PM) and 9 lb/h gas (PM_{10})	No Controls	09/14/1998	Champion International Corp. and Champion Clean Energy, Maine	BACT
0.06 lb/MMBtu (PM) and 0.06 lb/MMBtu (PM_{10})	No Controls	12/04/1998	Westbrook Power L.L.C., Maine	BACT
0.06 lb/MMBtu (PM)	No Controls	07/13/1998	Casco Ray Energy Company, Maine	BACT

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

pollutants), and the amount of risk accepted by the manufacturer. PM emission estimates typically are conservative due to the lack of feasible methods of control.

E.5.2.3 Summary

Pipeline quality natural gas will be the only fuel used in the combustion turbines at the generation plant and is accepted as BACT. The combustion turbines will emit no more than 25.5 lb/hr (with or without the duct burner being in operation) of PM and 25.4 lb/hr (with or without the duct burner being in operation) per turbine of PM_{10} on a 24-hour average basis. The emission limits of 25.5 lb/hr for PM and 25.4 lb/hr for PM_{10} do not include expected emissions of $2(NH_4(SO_4))$, but include both the front and back halves of the stack exhaust analysis.

E.5.3 HRSG Duct Burner BACT for PM and PM_{10}

E.5.3.1 Previous BACT Determinations

The RBLC database was reviewed for recent combined-cycle gas turbine (SCC Code 20100201) projects. None of the projects listed above included any specific PM emission limits for HRSG duct burners separate from PM emission limits for the combustion turbines.

E.5.3.2 Technical Feasibility and Ranking of Alternatives

Duct burners fire fuel into the exhaust from combustion turbines. The extra fuel consumes only oxygen present in the combustion turbine exhaust with no addition of extra air. Thus it is impossible to control a duct burner using an add-on control device separately from the combustion turbine.

E.5.3.3 Summary

The HRSG duct burners at the generation plant will fire only pipeline-quality natural gas. Use of pipeline-quality natural gas is accepted as BACT.

E.6 BACT for SO_2 and H_2SO_4 Mist

E.6.1 Theoretical Formation and Control of SO2 and H2SO4 Mist

Small quantities of sulfur are present in the natural gas, primarily due to the addition of mercaptans for odorizing natural gas. Sulfur present in natural gas is oxidized to sulfur dioxide (SO_2) during the combustion process in the CGTs and HRSGs. Some of the SO_2 is further oxidized to sulfur trioxide (SO_3) during the combustion process. Use of an oxidation catalyst for controlling CO emissions also can result in oxidation of additional SO_2 to SO_3. Some of the SO_3 present in the exhaust gas combines with the moisture and forms H_2SO_4 mist.

E.6.2 Previous BACT Determinations

Table E-10 summarizes the database search of EPA’s RBLC for recent simple-cycle, cogeneration or combined-cycle gas turbine (SCC Code 20100201) projects. The majority of the permits that have been issued for natural-gas-fired equipment using internal combustion do not include a BACT determination or emission limits for SO_2 and H_2SO_4 mist. For some permits that do include such determination or emission limitations, natural gas use or no controls are the only types of control technologies that are listed in the database for control of SO_2 and H_2SO_4 mist emissions. Use of low-sulfur oil is listed as the control technology for combustion turbines that also use oil for combustion. Neither BACT determination nor SO_2 and H_2SO_4 emission limits for such units are listed in Table E-10.

E.6.3 CGT and HRSG Duct Burner BACT for SO2 and H2SO4 Mist

The combustion turbines and HRSG duct burners at the generation plant will fire only pipeline-quality natural gas. Use of pipeline-quality natural gas has been generally accepted as BACT for SO_2 emissions. Also, because SO_2 is a precursor for H_2SO_4 mist emissions, use of pipeline-quality natural gas also is accepted as BACT for H_2SO_4 mist emissions.

E.7 BACT for Diesel-Fuel-Fired Fire Pump

E.7.1 Previous BACT Determinations

Table E-11 summarizes the database search of EPA’s RBLC for diesel-fuel-fired fire pumps that have been permitted for installation at various types of facilities in recent years. Generally, pollution prevention, good combustion, limits on diesel fuel use or operating hours, and limit on sulfur content in diesel fuel are the various types of control technologies that are listed in the database.

TABLE E-10

Recent SO_2 and H_2SO_4 Mist Emission Limits for Simple-Cycle, Cogeneration, or Combined-Cycle Gas Turbine Projects

Pollutant	Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
SO_X	1.5 lb/hr	No Controls Feasible	02/19/1992	Thermo Industries, Ltd., Colorado	Other
SO_2	3.2 tons/yr	No Controls Feasible	07/20/1994	Brush Cogeneration Partnership, Colorado	Other
SO_2	0.95 ton/yr	Pollution Prevention, Natural Gas Combustion	05/11/1993	Phoenix Power Partners, Colorado	Other
SO_x	0.039 lb/MMBtu	No Controls Feasible	07/07/1989	Pratt & Whitney, UTC, Connecticut	BACT
SO_X	0.0022 lb/MMBtu	Pollution Prevention, Natural Gas as Primary Fuel (0.8 gr/100 scf), Low Sulfur Oil (0.05%W)	04/16/1999	PDC El Paso Milford LLC, Connecticut	BACT
SO_2	-	Pollution Prevention, Natural Gas as Fuel	03/14/1991	Florida Power and Light, Florida	BACT
H_2SO_4	-				
SO_2	40 lb/hr	Pollution Prevention, Low Sulfur in Natural Gas	12/14/1992	Auburndale Power Partners, LP, Florida	BACT
H_2SO_4	7.5 lb/hr				
SO_2	0.99 lb/hr	Pollution Prevention, Low Sulfur in Natural Gas	02/25/1994	Florida Power Corporation, Florida	BACT
SO_2	0.02 gr/dscf	Pollution Prevention, Natural Gas Only	10/15/1999	Duke Energy New Somyrna Beach Power Co. LP, Florida	BACT
SO_2	12 lb/hr	No Controls Feasible	09/14/1998	Champion International Corp. & Champion Clean Energy, Maine	BACT
SO_2	0.006 lb/MMBtu	No Controls Feasible	07/13/1998	Casco Ray Energy Co, Maine	BACT
SO_2	9.5 ppm @ 15% O_2	Pipeline Quality Natural Gas, Low Sulfur Fuel Oil, Good Combustion	11/22/1999	Lincoln Electric System, Nebraska	BACT
SO_2	0.0069 lb/MMBtu	Pollution Prevention, Natural Gas/Low Sulfur Fuel Oil	04/01/1991	Lakewood Cogeneration, L.P., New Jersey	BACT
SO_2	0.0026 lb/MMBtu	Pollution Prevention, Use of Natural Gas	06/09/1993	Newark Bay Cogeneration Partnership, L.P., New Jersey	BACT

Note: Emission limit measurement units are presented as specifically noted in the database.
gr/dscf = grains per dry standard cubic foot

TABLE E-11
Recent Emission Limits for Diesel-Fuel-Fired Fire Pumps

Pollutant	Emission Limit	Control Technology	Permit Issuance Date	Company Name and Location	BACT/ LAER
NO_X	7.13 lb/hr	Pollution Prevention, Diesel Fuel Use Limit	06/10/1997	Grain Processing Corp., Indiana	BACT
CO	1.54 lb/hr	Pollution Prevention, Diesel Fuel Use Limit			
PM_{10}	0.5 lb/hr	No Controls Feasible			
NO_X	10.4 lb/hr	Pollution Prevention, Limit Operating Hours	11/14/1989	Oxy NGL, Inc., Louisiana	BACT
CO	1.7 lb/hr	No Controls Feasible			
PM	0.26 lb/MMBtu	Limit Operating Hours	10/10/1998	LSP – Cottage Grove, L.P., Minnesota	BACT
PM_{10}	0.26 lb/MMBtu				
NO_X	1.85 lb/MMBtu				
VOC	0.71 lb/MMBtu				
H_2SO_4	0.0017 lb/MMBtu				
NO_X	1.3 lb/MMBtu	Pollution Prevention, Lean Burn Engine	09/01/1992	Pasny/Holtsville Combined Cycle Power Plant, New York	BACT
SO_2	0.2% Sulfur in Diesel	Pollution Prevention, Low Sulfur Oil			
CO	0.71 lb/MMBtu	Pollution Prevention, Combustion Control			
NO_X	4.25 lb/MMBtu, 6.25 lb/hr	No Controls Feasible	12/10/1994	Kamine/BesiCorp Syracuse LP, New York	BACT
CO	2.88 lb/MMBtu, 4.23 lb/hr				
VOC	0.055 lb/MMBtu, 0.08 lb/hr				
PM/PM_{10}	0.2 lb/MMBtu, 0.29 lb/hr	Pollution Prevention, 0.15% Sulfur Content in Diesel			
NO_X	1.1 tons/yr	Pollution Prevention, Limit Operating Hours	08/28/1996	Vaughan Furniture Company, Virginia	BACT

Note: Emission limit measurement units are presented as specifically noted in the database.

E.7.2 BACT Determination for Diesel-Fuel-Fired Fire Pump

The maximum hours of operation for the diesel-fuel-fired fire pump are proposed to be 1 hour per day, with an annual limit of 10 hours per year. Highway grade low-sulfur diesel fuel with sulfur content less than 0.05 percent will be used as the fuel for the fire pump. The emissions of PM, PM_{10}, NO_X, SO_2, CO, and VOCs from the fire pump have been estimated to be 0.04, 0.04, 3.91, 0.10, 0.17, and 0.13 lb/hr, respectively. Based on the annual limit of 10 hours per year, the annual emissions of PM, PM_{10}, NO_X, SO_2, CO, and VOCs from the fire pump have been estimated to be 0.0002, 0.0002, 0.0196, 0.0005, 0.0009, and 0.0007 ton/yr, respectively. The emissions of these pollutants from the fire pump, therefore, are insignificant.

The maximum heat input rate for the fire pump is approximately 1.999 MMBtu/hr. The emission rates of 0.04, 0.04, 3.91, 0.10, 0.17, and 0.13 lb/hr for PM, PM_{10}, NO_X, SO_2, CO, and VOCs are equivalent to approximately 0.02, 0.02, 1.96, 0.05, 0.09, and 0.07 lb/MMBtu, which are comparable to or lower than the emission limits listed in Table E-11.

Pollution prevention, good combustion practices, and use of low-sulfur diesel fuel, therefore, have been determined to be BACT for the diesel-fuel-fired fire pump.

ATTACHMENT F

Best Available Control Technology Analysis for Toxics

The Starbuck Power Company's (SPC) Starbuck Power Project (SPP) is subject to the control requirements for new sources of toxic air pollutants (TAP) provided in 173-460 *Washington Administrative Code* (WAC). 173-460-060 WAC requires that a person shall not establish, operate, or cause to be established or operated any new TAP source that is likely to increase TAP emissions without installing and operating the best available control technology for air toxic compounds (T-BACT). 173-460-020(4) WAC states that T-BACT applies to each TAP or mixture of TAPs discharged, taking into account the potency quantity and toxicity of each TAP and or mixture of TAPs discharged.

This attachment presents the T-BACT analysis for the various TAP emission sources proposed to be installed at the generation plant. These sources are four identical natural-gas-fired combustion gas turbines (CGTs), four identical heat recovery steam generators (HRSGs) with supplemental duct firing (duct burners), and a diesel-fuel-fired fire pump.

F.1 TAP Emissions

The following Class A or Class B TAPs are emitted from the combustion of natural gas in the CGTs, HRSGs, and fire pump and from the use of ammonia in the selective catalytic reduction (SCR) system for controlling oxides of nitrogen (NO_X) emissions from the CGTs and HRSGs: ammonia, sulfuric acid mist, acetaldehyde, acrolein, ethylbenzene, polycyclic aromatic hydrocarbons (PAH), xylenes, benzo(a)anthracene, benzene, dichlorobenzene, formaldehyde, hexane, naphthalene, and toluene.

F.2 T-BACT Analysis

An oxidation catalyst is proposed to be installed to meet the BACT requirements for carbon monoxide (CO) emissions from the CGTs and HRSGs. In addition to controlling CO emissions, the oxidation catalyst also results in a reduction in volatile organic compounds (VOC) emissions from the CGTs and HRSGs. The CO and VOC emissions are a result of incomplete combustion of natural gas in the CGTs and HRSGs. Except for ammonia and sulfuric acid mist, all other TAPs are also a result of incomplete combustion of natural gas in the CGTs and HRSGs. Use of an oxidation catalyst will not only result in oxidation of CO to carbon dioxide (CO_2) and VOCs to CO_2 and water, but will also result in oxidation of some of the TAPs to CO_2 and water, as all of the TAPs except ammonia and sulfuric acid mist are VOCs. Therefore, the use of an oxidation catalyst for controlling CO emissions from the CGTs and HRSGs has been determined to meet the T-BACT requirements for acetaldehyde, acrolein, ethylbenzene, PAH, xylenes, benzene, dichlorobenzene, formaldehyde, hexane, naphthalene, and toluene.

Ammonia is used in the SCR process, which has been determined to be BACT for controlling NO_X emissions from the CGTs and HRSGs. An NO_X emissions limit of 2.5 parts per million by volume dry (ppmvd) (corrected to 15 percent O_2) based on a 24-hour averaging basis with 10 ppmvd ammonia slip (corrected to 15 percent O_2) based on a 24-hour average basis is proposed as the BACT for controlling NO_X emissions from the CGTs and HRSGs. Ammonia emissions can be reduced below 10 ppmvd (corrected to 15 percent O_2) based on a 24-hour average basis; however, reduction in ammonia emissions will mean increased NO_X emissions. As a result of the acceptable source impact level (ASIL) analysis, the maximum incremental ambient impact for ammonia was found to be well below the ASIL when ammonia concentration is equal to 10 ppmvd (corrected to 15 percent O_2). Therefore, it has been determined that limiting the ammonia emissions to 10 ppmvd (corrected to 15 percent O_2) based on a 24-hour average basis would satisfy the T-BACT requirements for controlling ammonia emissions.

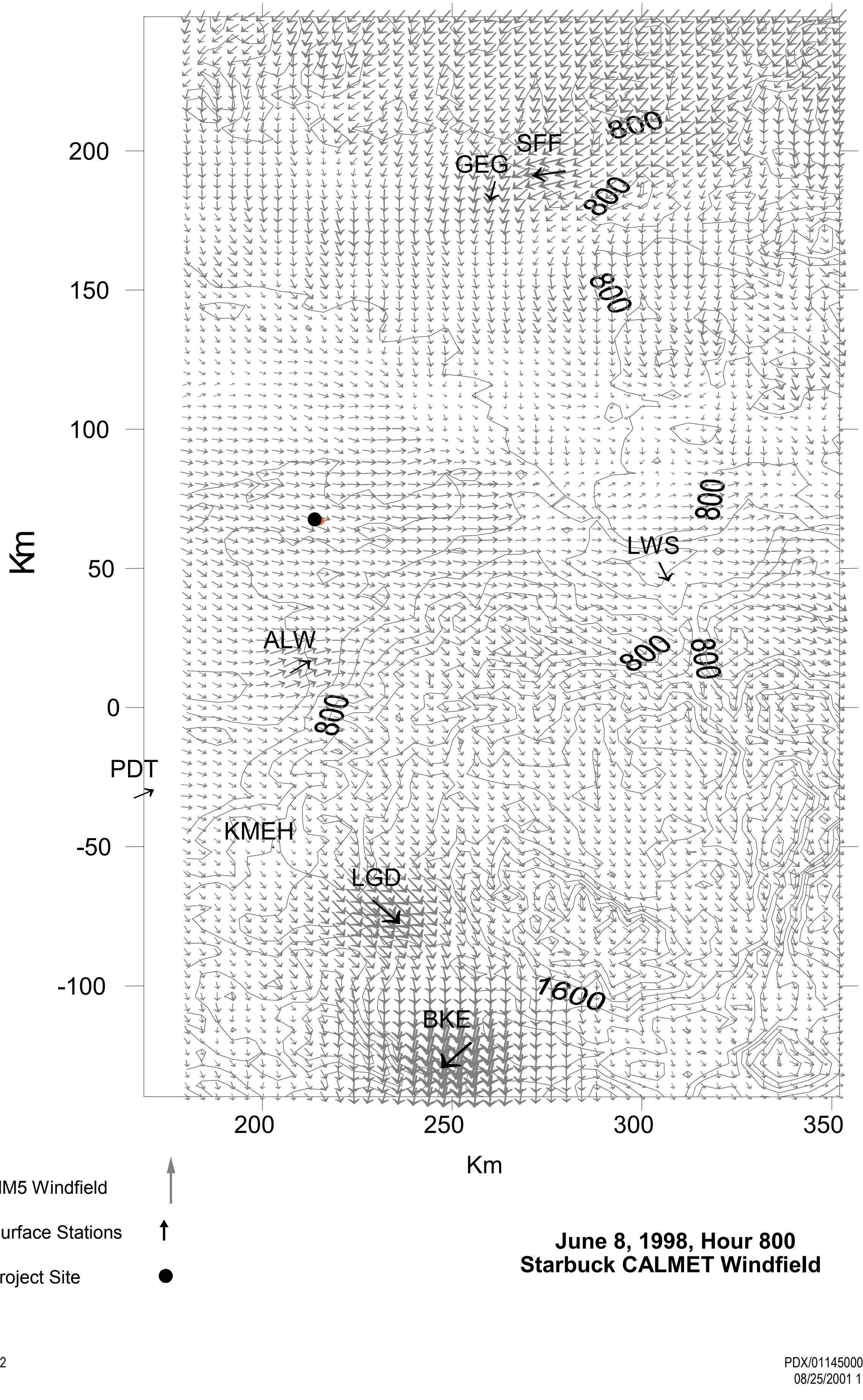
Small quantities of sulfur are present in the natural gas, primarily due to the addition of mercaptans for odorizing natural gas. Sulfur present in natural gas is oxidized to sulfur dioxide (SO_2) during the combustion process in the CGTs and HRSGs. Some of the SO_2 is further oxidized to sulfur trioxide (SO_3) during the combustion process. Use of an oxidation catalyst for controlling CO emissions also can result in oxidation of additional SO_2 to SO_3. Some of the SO_3 present in the exhaust gas combines with the moisture and forms sulfuric acid mist. Use of pipeline-quality natural gas has been determined to be BACT for controlling SO_2 emissions from the CGTs and HRSGs. The oxidation catalyst has been determined to be BACT for controlling CO emissions from the CGTs and HRSGs. Sulfuric acid mist emissions might be reduced if the oxidation catalyst were not present; however, that would result in excess CO emissions, and the sulfur present in natural gas would be emitted in other forms in the exhaust gas. Use of pipeline-quality natural gas and limiting the sulfuric acid mist emissions to 1.36 pounds per hour or 32.64 pounds per day per CGT and HRSG, therefore, is determined to meet the T-BACT requirements for controlling sulfuric acid mist emissions from CGTs and HRSGs. As a result of the ASIL analysis, the maximum incremental ambient impact for sulfuric acid mist also was found to be well below the ASIL, when the emission rate of sulfuric acid mist is equal to 1.36 pounds per hour per CGT and HRSG.

Pollution prevention, good combustion practices, and use of low-sulfur diesel fuel has been determined to be BACT for the diesel-fuel-fired fire pump. These practices also will result in reduction of TAP emissions from the fire pump. Pollution prevention, good combustion practices, and use of low-sulfur diesel fuel, therefore, have been determined to meet the T-BACT requirements for the fire pump.

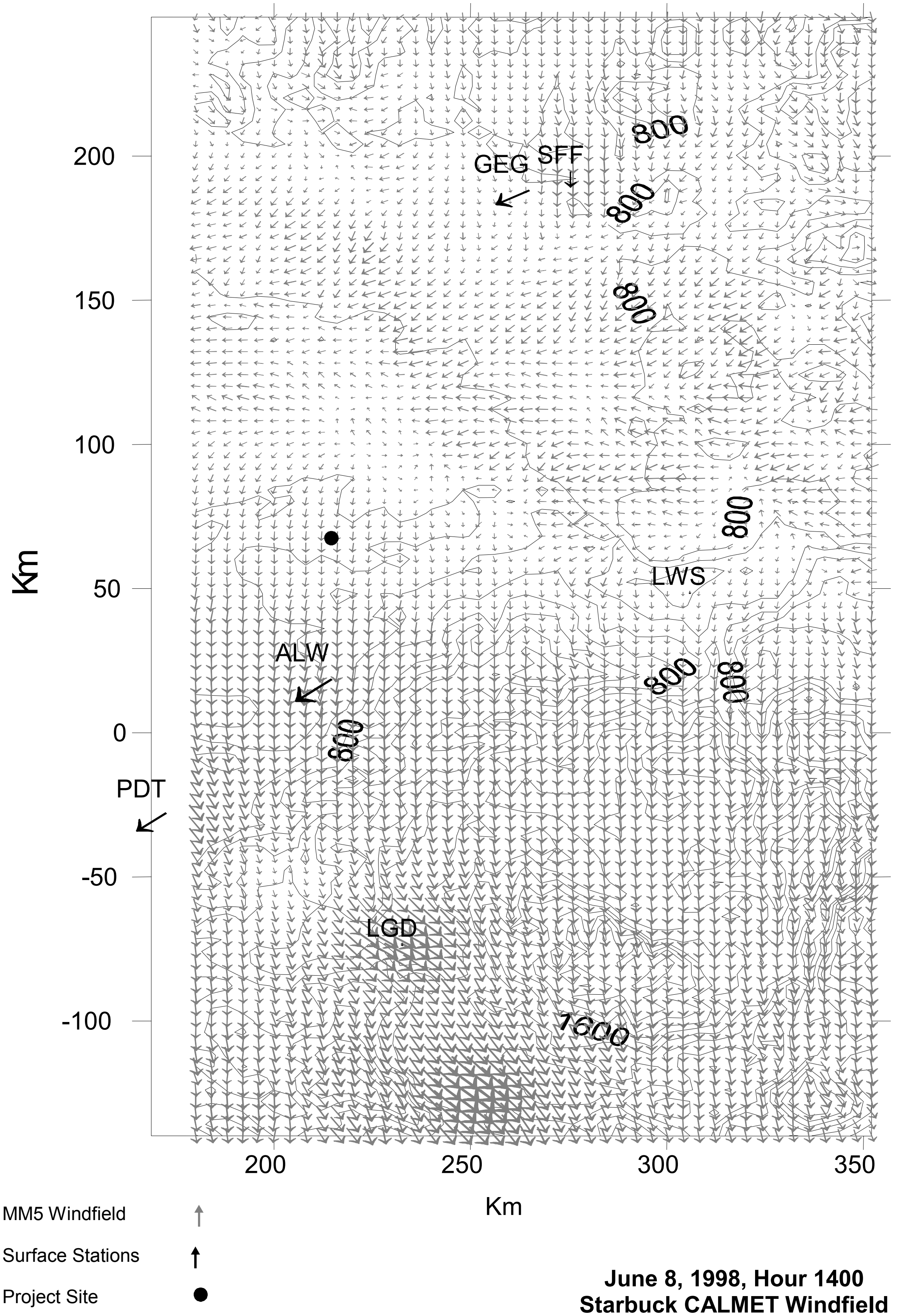
ATTACHMENT G

Windfields

Figures will follow.



**June 8, 1998, Hour 800
Starbuck CALMET Windfield**



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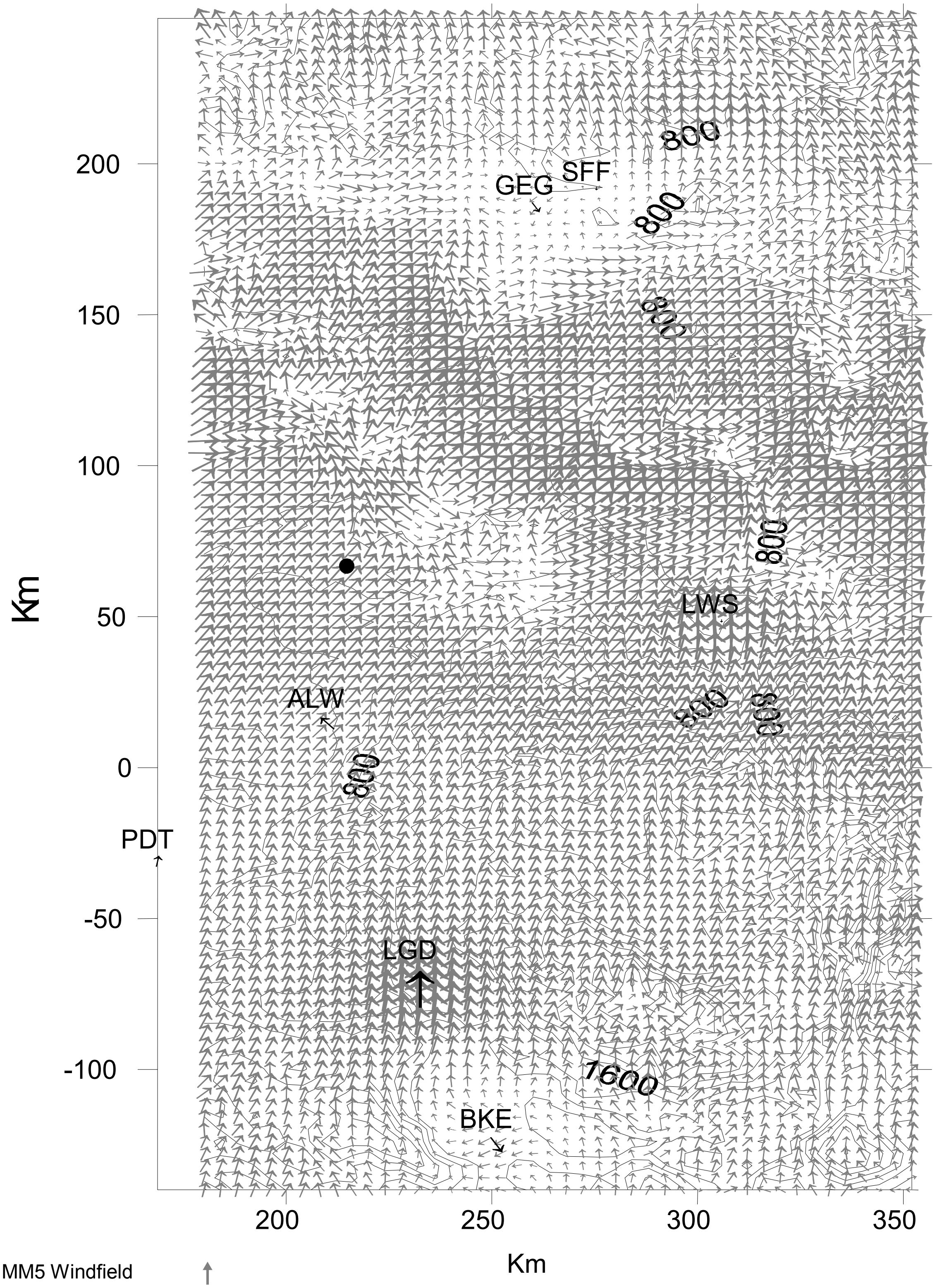
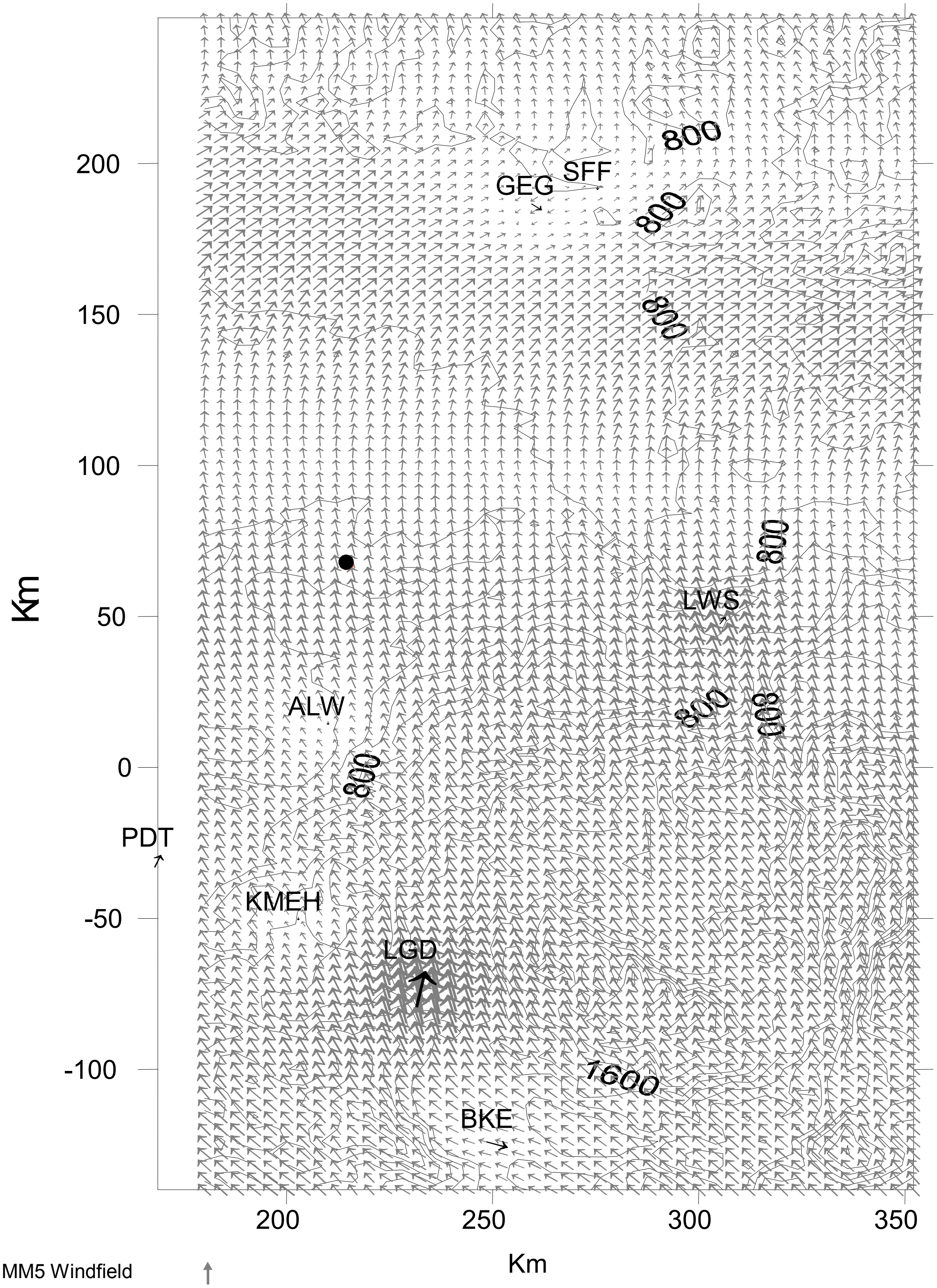


MM5 Windfield ↑

Surface Stations ↑

Project Site ●

December 25, 1998, Hour 800
Starbuck CALMET Windfields



December 25, 1998, Hour 1400
Starbuck CALMET Windfield

ATTACHMENT H

Class I Modeling Files

Electronic copies are available upon request.

ATTACHMENT I

Performance Information

Tables I-1 and I-2 follow.

Table I-1
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

Case Description	1 100% Load STIG Hot Day Duct Firing On	2 100% Load Hot Day Duct Firing Off	3 100% Load STIG Avg Ambient Duct Firing On	4 100% Load Avg Ambient Duct Firing On	5 100% Load Avg Ambient Duct Firing Off	6 100% Load Cold Day Duct Firing On	7 100% Load Cold Day Duct Firing Off	8 85% Load Cold Day Duct Firing Off	9 70% Load Cold Day Duct Firing Off	10 85% Load Avg Ambient Duct Firing Off	11 70% Load Avg Ambient Duct Firing Off	12 85% Load Hot Day Duct Firing Off	13 70% Load Hot Day Duct Firing Off
Image File	NPE501FHotDayFireSTIG.img	NPE501FHotDay.img	NPE501FAvgFireSTIG.img	NPE501FAvgFire.img	NPE501FAvgDay.img	NPE501FColdFire.img	NPE501FColdDay.img	NPE501FColdDay85PL.img	NPE501FColdDay70PL.img	NPE501FAvgDay85PL.img	NPE501FAvgDay70PL.img	NPE501FHotDay85PL.img	NPE501FHotDay70PL.img
Run Date	05/23/01pcNT	05/28/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT
Ambient Temperature	101 F	101 F	51.1 F	51.1 F	51.1 F	-20 F	-20 F	-20 F	-20 F	51.1 F	51.1 F	101 F	101 F
Number of CTG/HRSG Units Operating	2	2	2	2	2	2	2	2	2	2	2	2	2
CTG Model	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F
CTG Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of base load)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85.00%	70.00%	85.00%	70.00%	85.00%	70.00%
CTG Evaporative Cooler	On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
HRSG Firing	Fired	Unfired	Fired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
HRSG Model	Design: 1815 psia Maximum STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure
STG Output	193.6 MW	153.3 MW	220.9 MW	242.2 MW	180.8 MW	243.8 MW	184.2 MW	155.6 MW	138.1 MW	152.3 MW	137.9 MW	127.3 MW	119.6 MW
STG Throttle Conditions, psia/F	1909P/1050T	1339P/1050T	1908P/1050T	1907P/1050T	1361P/1050T	1908P/1030T	1359P/1010T	1154P/966T	1040P/971T	1154P/1004T	1054P/1015T	1108P/1027T	1037P/1041T
STG Hot Reheat Conditions, psia/F	339P/1050T	288P/1041T	336P/1050T	392P/1047T	295P/1032T	398P/1013T	301P/992T	260P/951T	232P/956T	254P/987T	229P/999T	240P/1010T	222P/1024T
Condenser Pressure	7 in HgA	6.3 in HgA	2 in HgA	2.3 in HgA	2.3 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	2.19 in HgA	1.98 in HgA	5.09 in HgA	4.48 in HgA
New & Clean Performance per Block													
Number of CTG/HRSG Units Operating	2	2	2	2	2	2	2	2	2	2	2	2	2
Gross CTG Output, kW (each)	189,890	168,850	201,690	181,480	181,480	209,790	209,790	181,430	149,210	154,090	126,660	128,800	105,810
Gross CTG Output, kW (total)	379,780	337,700	403,380	362,960	362,960	419,580	419,580	362,860	298,420	308,180	253,320	257,600	211,620
Gross CTG Heat Rate, Btu/kWh (LHV)	9,003.0	9,350.0	8,888.0	9,205.0	9,205.0	8,935.0	8,935.0	9,109.0	9,500.0	9,460.0	9,931.0	9,901.0	10,604.0
Gross CTG Heat Rate, Btu/kWh (HHV)	9,992.0	10,377.0	9,865.0	10,216.0	10,216.0	9,916.0	9,916.0	10,109.1	10,543.0	10,498.6	11,021.4	10,988.0	11,768.2
CTG Heat Input, MBtu/h (LHV) (each)	1,709.6	1,578.7	1,792.6	1,670.5	1,670.5	1,874.5	1,874.5	1,652.6	1,417.5	1,457.7	1,257.9	1,275.2	1,122.0
CTG Heat Input, MBtu/h (HHV) (each)	1,897.4	1,752.2	1,989.7	1,854.0	1,854.0	2,080.3	2,080.3	1,834.1	1,573.1	1,617.7	1,396.0	1,415.3	1,245.2
CTG Heat Input, MBtu/h (LHV) (total per Block)	3,419.2	3,157.5	3,585.2	3,341.0	3,341.0	3,748.9	3,748.9	3,305.3	2,835.0	2,915.4	2,515.7	2,550.5	2,244.0
CTG Heat Input, MBtu/h (HHV) (total per Block)	3,794.8	3,504.3	3,979.3	3,708.0	3,708.0	4,160.6	4,160.6	3,668.2	3,146.2	3,235.5	2,791.9	2,830.5	2,490.4
Duct Burner Heat Input, MBtu/h (LHV) (each)	217.3	0.0	206.8	248.6	0.0	245.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (each)	241.1	0.0	229.5	275.9	0.0	272.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (LHV) per Block	434.5	0.0	413.6	497.2	0.0	490.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) pre Block	482.2	0.0	459.1	551.8	0.0	544.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross STG Output, kW (per Block)	193,590	153,250	220,920	242,170	180,760	243,770	184,230	155,640	138,110	152,310	137,880	127,270	119,550
Gross Block Output, kW	573,370	490,950	624,300	605,130	543,720	663,350	603,810	518,500	436,530	460,490	391,200	384,870	331,170
Auxiliary Power/Losses, kW	14,500	12,996	15,493	16,063	14,006	16,315	14,320	13,164	12,351	12,861	12,186	11,845	11,426
Auxiliary Power/Losses, percent of gross	2.53%	2.65%	2.48%	2.65%	2.58%	2.46%	2.37%	2.54%	2.83%	2.79%	3.11%	3.08%	3.45%
Block Heat Input, MBtu/h (LHV)	3,853.7	3,157.5	3,998.9	3,838.2	3,341.0	4,239.9	3,748.9	3,305.3	2,835.0	2,915.4	2,515.7	2,550.5	2,244.0
Block Heat Input, MBtu/h (HHV)	4,277.0	3,504.3	4,438.4	4,259.8	3,708.0	4,705.4	4,160.6	3,668.2	3,146.2	3,235.5	2,791.9	2,830.5	2,490.4
Net Block Output, kW	558,870	477,954	608,807	589,067	529,714	647,035	589,490	505,336	424,179	447,629	379,014	373,025	319,744
Net Block Heat Rate, Btu/kWh (LHV)	6,895	6,606	6,568	6,516	6,307	6,553	6,360	6,541	6,683	6,513	6,638	6,837	7,018
Net Block Heat Rate, Btu/kWh (HHV)	7,653	7,332	7,290	7,231	7,000	7,272	7,058	7,259	7,417	7,228	7,366	7,588	7,789
Net Block Efficiency (LHV)	49.48%	51.65%	51.95%	52.37%	54.10%	52.07%	53.65%	52.17%	51.05%	52.39%	51.40%	49.90%	48.62%
Net Block Efficiency (HHV)	44.58%	46.54%	46.80%	47.18%	48.74%	46.92%	48.34%	47.00%	46.00%	47.21%	46.32%	44.97%	43.81%
Plant Heat Input, MBtu/h (LHV)	7,707.3	6,315.0	7,997.7	7,676.5	6,682.1	8,479.7	7,497.9	6,610.6	5,670.0	5,830.8	5,031.4	5,101.0	4,488.0
Plant Heat Input, MBtu/h (HHV)	8,554.0	7,008.6	8,876.9	8,519.6	7,416.0	9,410.7	8,321.1	7,336.4	6,292.5	6,470.9	5,583.9	5,661.0	4,980.8
Net Plant Output, kW	1,117,740	955,908	1,217,615	1,178,134	1,059,428	1,294,070	1,178,980	1,010,672	848,358	895,258	758,029	746,050	639,489
Net Plant Heat Rate, Btu/kWh (LHV)	6,895	6,606	6,568	6,516	6,307	6,553	6,360	6,541	6,683	6,513	6,638	6,837	7,018
Net Plant Heat Rate, Btu/kWh (HHV)	7,653	7,332	7,290	7,231	7,000	7,272	7,058	7,259	7,417	7,228	7,366	7,588	7,789
Net Plant Efficiency (LHV)	49.48%	51.65%	51.95%	52.37%	54.10%	52.07%	53.65%	52.17%	51.05%	52.39%	51.40%	49.90%	48.62%
Net Plant Efficiency (HHV)	44.58%	46.54%	46.80%	47.18%	48.74%	46.92%	48.34%	47.00%	46.00%	47.21%	46.32%	44.97%	43.81%

Table I-1
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

Case Description		1 100% Load STIG Hot Day Duct Firing On	2 100% Load Hot Day Duct Firing Off	3 100% Load STIG Avg Ambient Duct Firing On	4 100% Load Avg Ambient Duct Firing On	5 100% Load Avg Ambient Duct Firing Off	6 100% Load Cold Day Duct Firing On	7 100% Load Cold Day Duct Firing Off	8 85% Load Cold Day Duct Firing Off	9 70% Load Cold Day Duct Firing Off	10 85% Load Avg Ambient Duct Firing Off	11 70% Load Avg Ambient Duct Firing Off	12 85% Load Hot Day Duct Firing Off	13 70% Load Hot Day Duct Firing Off
Image File		NPE501FHotDayFireSTIG.img	NPE501FHotDay.img	NPE501FAvgFireSTIG.img	NPE501FAvgFire.img	NPE501FAvgDay.img	NPE501FColdFire.img	NPE501FColdDay.img	NPE501FColdDay85PL.img	NPE501FColdDay70PL.img	NPE501FAvgDay85PL.img	NPE501FAvgDay70PL.img	NPE501FHotDay85PL.img	NPE501FHotDay70PL.img
Run Date		05/23/01pcNT	05/28/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT
Ambient Temperature		101 F	101 F	51.1 F	51.1 F	51.1 F	-20 F	-20 F	-20 F	-20 F	51.1 F	51.1 F	101 F	101 F
Number of CTG/HRSG Units Operating		2	2	2	2	2	2	2	2	2	2	2	2	2
CTG Model		SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F
CTG Fuel		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of base load)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85.00%	70.00%	85.00%	70.00%	85.00%	70.00%
CTG Evaporative Cooler		On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
HRSG Firing		Fired	Unfired	Fired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
HRSG Model		Design: 1815 psia Maximum STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure
STG Output		193.6 MW	153.3 MW	220.9 MW	242.2 MW	180.8 MW	243.8 MW	184.2 MW	155.6 MW	138.1 MW	152.3 MW	137.9 MW	127.3 MW	119.6 MW
STG Throttle Conditions, psia/F		1909P/1050T	1339P/1050T	1908P/1050T	1907P/1050T	1361P/1050T	1908P/1030T	1359P/1010T	1154P/966T	1040P/971T	1154P/1004T	1054P/1015T	1108P/1027T	1037P/1041T
STG Hot Reheat Conditions, psia/F		339P/1050T	288P/1041T	336P/1050T	392P/1047T	295P/1032T	398P/1013T	301P/992T	260P/951T	232P/956T	254P/987T	229P/999T	240P/1010T	222P/1024T
Condenser Pressure		7 in HgA	6.3 in HgA	2 in HgA	2.3 in HgA	2.3 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	2.19 in HgA	1.98 in HgA	5.09 in HgA	4.48 in HgA
Combustion Turbine Generator (each)														
Ambient Conditions	Pressure, psia	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
	Temperature, F	101	101	51.1	51.1	51.1	-20	-20	-20	-20	51.1	51.1	101	101
	Relative Humidity	18.00%	18.00%	58.00%	58.00%	58.00%	80.00%	80.00%	80.00%	80.00%	58.00%	58.00%	18.00%	18.00%
Compressor Inlet Conditions	Temperature, F	73.00	73.00	51.10	51.10	51.10	-20	-20	-20	-20	51.10	51.10	101.00	101.00
	Relative Humidity	78.00%	78.00%	58.00%	58.00%	58.00%	80.00%	80.00%	80.00%	80.00%	58.00%	58.00%	18.00%	18.00%
Evaporative Cooler Effectiveness		85.00%	85.00%	0.00%	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Steam Injection	Flowrate, lb/h	114570	0	120140	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Injection Fluid	Pressure, psia	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Injection Fluid	Temperature, F	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0	550.0
CTG Exhaust	Flowrate, lb/h	3,530,215.	3,409,855.	3,729,530.	3,604,060.	3,604,060.	3,955,835.	3,955,835.	3,707,100.	3,271,185.	3,379,295.	2,989,455.	3,069,530.	2,783,300.
	Temperature, F	1,116.0	1,116.0	1,100.0	1,098.0	1,098.0	1,052.0	1,052.0	996.0	997.0	1,037.0	1,046.0	1,061.0	1,073.0
Generator Gross Output, Kw (each)		189,890	168,850	201,690	181,480	181,480	209,790	209,790	181,430	149,210	154,090	126,660	128,800	105,810
Heat Recovery Steam Generator (per unit)														
HRSG HP Steam	Flowrate, lb/h	584,777.	404,921.	584,306.	584,114.	411,691.	589,783.	418,198.	360,114.	322,777.	354,274.	321,265.	336,698.	312,873.
(after NRV)	Pressure, psia	2,019.0	1,415.5	2,017.5	2,016.9	1,438.8	2,018.0	1,436.8	1,220.5	1,099.5	1,220.2	1,114.4	1,172.1	1,096.8
	Temperature, F	1,056.0	1,054.6	1,056.1	1,056.0	1,054.7	1,036.2	1,014.7	971.0	975.0	1,008.3	1,019.5	1,031.4	1,044.7
	Enthalpy, Btu/lb	1,508.63	1,524.87	1,508.70	1,508.69	1,524.27	1,496.33	1,500.75	1,481.91	1,488.11	1,503.52	1,513.13	1,518.29	1,527.98
HP Evaporator Outlet	Flowrate, lb/h	554,372.	397,906.	563,305.	553,489.	411,503.	571,042.	418,198.	360,114.	322,777.	354,274.	321,265.	336,698.	312,873.
	Pressure, psia	2,087.6	1,455.3	2,087.6	2,085.3	1,480.5	2,089.7	1,479.6	1,254.8	1,129.0	1,253.7	1,143.7	1,203.3	1,125.1
	Temperature, F	641.9	592.2	641.9	641.7	594.5	642.0	594.4	572.9	559.5	572.8	561.2	567.6	559.1
	Enthalpy, Btu/lb	1,131.79	1,172.58	1,131.79	1,131.97	1,171.26	1,131.62	1,171.30	1,182.43	1,187.95	1,182.49	1,187.33	1,184.76	1,188.11
FW to HP ECON 1	Flowrate, lb/h	559,972.	401,927.	568,995.	559,083.	415,659.	576,810.	422,422.	363,752.	326,038.	357,851.	324,510.	340,098.	316,033.
	Pressure, psia	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0
	Temperature, F	304.7	301.7	301.5	309.6	301.2	311.8	304.5	295.5	287.1	293.7	285.5	291.5	284.9
	Enthalpy, Btu/lb	278.75	275.63	275.43	283.69	275.11	285.92	278.55	269.40	260.83	267.48	259.22	265.26	258.61
Duct Burner														
Fuel Mass Flow	Flowrate, lb/h	10400	0	9900	11900	0	11750	0	0	0	0	0	0	0
HRSG Hot Reheat Steam	Flowrate, lb/h	548,592.	468,980.	543,225.	637,784.	480,619.	654,370.	498,001.	436,266.	387,884.	420,349.	377,564.	393,878.	362,886.
	Pressure, psia	352.8	300.0	349.4	408.2	306.4	413.6	312.9	270.2	240.9	263.9	238.2	249.5	231.1
	Temperature, F	1,051.9	1,042.7	1,051.9	1,048.9	1,033.6	1,014.7	994.1	952.6	957.5	989.0	1,000.8	1,012.0	1,025.6
	Enthalpy, Btu/lb	1,552.28	1,548.85	1,552.37	1,549.20	1,543.82	1,530.71	1,522.69	1,502.11	1,505.60	1,521.42	1,528.39	1,533.99	1,541.64
Cold Reheat Steam from STG	Flowrate, lb/h	464,712.	397,377.	458,856.	573,230.	404,019.	578,793.	410,406.	353,404.	316,763.	347,673.	315,279.	330,425.	307,044.
	Pressure, psia	384.2	326.0	380.7	447.8	333.2	454.7	340.9	294.0	261.8	286.8	258.6	270.8	250.6
	Temperature, F	641.9	687.5	640.3	672.9	688.4	659.3	659.8	629.6	632.4	655.7	664.1	672.3	682.3
	Enthalpy, Btu/lb	1,332.40	1,360.86	1,331.76	1,345.59	1,360.93	1,337.48	1,345.07	1,331.76	1,335.43	1,346.20	1,352.35	1,355.94	1,362.33
HRSG IP Steam	Flowrate, lb/h	72,544.	71,604.	79,894.	64,554.	76,600.	75,576.	87,596.	82,862.	71,121.	72,677.	62,285.	63,453.	55,842.
	Pressure, psia	384.2	326.0	380.7	447.8	333.2	454.7	341.0	293.9	261.8	286.8	258.6	270.8	250.7
	Temperature, F	583.4	559.9	584.1	587.5	562.1	590.2	563.8	549.3	538.5	547.5	537.6	542.0	534.2
	Enthalpy, Btu/lb	1,299.04	1,290.48	1,299.74	1,295.97	1,291.11	1,297.03	1,291.43	1,287.39	1,284.31	1,287.04	1,284.06	1,285.39	1,282.94
IP FW to IP ECON	Flowrate, lb/h	73,277.	72,327.	80,701.	65,206.	77,374.	76,340.	88,480.	83,699.	71,839.	73,411.	62,915.	64,094.	56,406.
	Pressure, psia	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
	Temperature, F	301.4	298.4	298.2	306.2	297.9	308.4	301.3	292.4	284.0	290.5	282.4	288.3	281.8
	Enthalpy, Btu/lb	272.22	269.12	268.91	277.14	268.59	279.37	272.03	262.90	254.37	260.99	252.76	258.78	252.15
IP Feedwater to CTG Rotor Air Cooler	Flowrate, lb/h	25,028.	24,960.	23,999.	24,172.	23,992.	24,220.	24,064.	14,731.	12,122.	20,106.	16,591.	21,783.	17,990.
(from IP BFP)	Pressure, psia	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
	Temperature, F	301.4	298.4	298.2	306.2	297.9	308.4	301.3	292.4	284.0	290.5	282.4	288.3	281.8
	Enthalpy, Btu/lb	272.22	269.12	268.91	277.14	268.59	279.37	272.03	262.90	254.37	260.99	252.76	258.78	252.15
IP FW to Fuel Gas Heat Exchanger	Flowrate, lb/h	61,119.	62,296.	66,007.	62,797.	66,140.	61,980.	64,754.	67,402.	61,183.	60,195.	54,896.	53,432.	49,174.
(from IP BFP exit)	Temperature, F	301.4	298.4	298.2	306.2	297.9	308.4	301.3	292.4	284.0	290.5	282.4	288.3	281.8
	Enthalpy, Btu/lb	272.22	269.12	268.91	277.14	268.59	279.37	272.03	262.90	254.37	260.99	252.76	258.78	252.15

Table I-1
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

Case Description		1 100% Load STIG Hot Day Duct Firing On	2 100% Load Hot Day Duct Firing Off	3 100% Load STIG Avg Ambient Duct Firing On	4 100% Load Avg Ambient Duct Firing On	5 100% Load Avg Ambient Duct Firing Off	6 100% Load Cold Day Duct Firing On	7 100% Load Cold Day Duct Firing Off	8 85% Load Cold Day Duct Firing Off	9 70% Load Cold Day Duct Firing Off	10 85% Load Avg Ambient Duct Firing Off	11 70% Load Avg Ambient Duct Firing Off	12 85% Load Hot Day Duct Firing Off	13 70% Load Hot Day Duct Firing Off
Image File		NPE501FHotDayFireSTIG.img	NPE501FHotDay.img	NPE501FAvgFireSTIG.img	NPE501FAvgFire.img	NPE501FAvgDay.img	NPE501FColdFire.img	NPE501FColdDay.img	NPE501FColdDay85PL.img	NPE501FColdDay70PL.img	NPE501FAvgDay85PL.img	NPE501FAvgDay70PL.img	NPE501FHotDay85PL.img	NPE501FHotDay70PL.img
Run Date		05/23/01pcNT	05/28/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT
Ambient Temperature		101 F	101 F	51.1 F	51.1 F	51.1 F	-20 F	-20 F	-20 F	-20 F	51.1 F	51.1 F	101 F	101 F
Number of CTG/HRSG Units Operating		2	2	2	2	2	2	2	2	2	2	2	2	2
CTG Model		SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F
CTG Fuel		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of base load)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85.00%	70.00%	85.00%	70.00%	85.00%	70.00%
CTG Evaporative Cooler		On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
HRSG Firing		Fired	Unfired	Fired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
HRSG Model		Design: 1815 psia Maximum STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure
STG Output		193.6 MW	153.3 MW	220.9 MW	242.2 MW	180.8 MW	243.8 MW	184.2 MW	155.6 MW	138.1 MW	152.3 MW	137.9 MW	127.3 MW	119.6 MW
STG Throttle Conditions, psia/F		1909P/1050T	1339P/1050T	1908P/1050T	1907P/1050T	1361P/1050T	1908P/1030T	1359P/1010T	1154P/966T	1040P/971T	1154P/1004T	1054P/1015T	1108P/1027T	1037P/1041T
STG Hot Reheat Conditions, psia/F		339P/1050T	288P/1041T	336P/1050T	392P/1047T	295P/1032T	398P/1013T	301P/992T	260P/951T	232P/956T	254P/987T	229P/999T	240P/1010T	222P/1024T
Condenser Pressure		7 in HgA	6.3 in HgA	2 in HgA	2.3 in HgA	2.3 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	2.19 in HgA	1.98 in HgA	5.09 in HgA	4.48 in HgA
IPP BFP Outlet	Flowrate, lb/h	766,536.	568,525.	770,755.	741,883.	583,353.	758,091.	599,722.	529,584.	471,183.	511,562.	458,910.	479,408.	439,604.
(after pipe, before IP CV)	Pressure, psia	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
	Temperature, F	301.4	298.4	298.2	306.2	297.9	308.4	301.3	292.4	284.0	290.5	282.4	288.3	281.8
	Enthalpy, Btu/lb	272.22	269.12	268.91	277.14	268.59	279.37	272.03	262.90	254.37	260.99	252.76	258.78	252.15
LP Steam	Flowrate, lb/h	58,838.	73,165.	48,772.	48,274.	68,896.	54,583.	76,349.	68,383.	58,246.	65,773.	55,070.	66,046.	56,780.
(after NRV)	Pressure, psia	59.1	54.3	57.0	65.2	54.4	66.9	56.6	49.2	43.3	47.9	42.4	46.0	41.8
	Temperature, F	580.4	547.6	587.5	586.5	554.8	590.6	557.2	544.4	533.9	539.8	531.1	529.8	524.1
	Enthalpy, Btu/lb	1,322.71	1,307.01	1,326.33	1,325.26	1,310.53	1,327.16	1,311.51	1,305.86	1,301.20	1,303.69	1,299.92	1,298.98	1,296.57
LP Steam from Rotor Air Cooler	Flowrate, lb/h	25,028.	24,960.	23,999.	24,172.	23,992.	24,220.	24,064.	14,731.	12,122.	20,106.	16,591.	21,783.	17,990.
	Pressure, psia	67.4	64.4	64.2	72.4	64.0	74.8	67.2	58.8	51.6	57.1	50.3	55.2	49.9
	Temperature, F	304.9	302.3	301.8	308.8	301.5	310.7	304.4	293.3	284.6	293.7	285.1	292.5	285.3
	Enthalpy, Btu/lb	1,182.30	1,181.65	1,181.42	1,183.17	1,181.36	1,183.65	1,182.08	1,178.25	1,175.57	1,178.91	1,176.19	1,178.80	1,176.41
LP Evaporator Water Outlet	Flowrate, lb/h	766,536.	568,525.	770,755.	741,883.	583,353.	758,091.	599,722.	529,584.	471,183.	511,562.	458,910.	479,408.	439,604.
	Pressure, psia	67.4	64.4	64.2	72.4	63.9	74.7	67.2	58.8	51.6	57.1	50.3	55.2	49.9
	Temperature, F	300.4	297.4	297.2	305.2	296.9	307.4	300.2	291.4	283.0	289.5	281.4	287.3	280.8
	Enthalpy, Btu/lb	270.19	267.07	266.87	275.12	266.55	277.36	269.99	260.85	252.29	258.93	250.68	256.71	250.07
Condensate to LP Economizer	Flowrate, lb/h	800,686.	617,208.	993,282.	907,234.	735,020.	985,274.	801,285.	718,985.	644,631.	661,488.	609,414.	524,118.	485,529.
	Pressure, psia	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
	Temperature, F	153.5	150.2	140.0	140.1	139.9	140.0	140.0	140.0	140.0	140.0	140.0	142.5	140.0
	Enthalpy, Btu/lb	122.04	118.74	108.60	108.64	108.49	108.54	108.54	108.56	108.54	108.56	108.60	111.07	108.63
Condensate from Recirculation	Flowrate, lb/h	0.	0.	197,508.	141,019.	106,313.	196,517.	148,756.	135,216.	126,863.	103,800.	111,638.	0.	6,748.
	Temperature, F	273.1	284.0	254.3	262.9	272.9	264.7	275.8	272.3	264.8	270.2	261.4	277.5	270.5
Condensate from Fuel Gas Heat Exchanger	Flowrate, lb/h	61,119.	62,296.	66,007.	62,797.	66,140.	61,980.	64,754.	67,402.	61,183.	60,195.	54,896.	53,432.	49,174.
	Pressure, psia	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
	Temperature, F	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
	Enthalpy, Btu/lb	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97	107.97
Condensate to HRSG	Flowrate, lb/h	739,568.	554,913.	729,766.	703,418.	562,568.	726,777.	587,774.	516,367.	456,584.	497,493.	442,881.	470,685.	429,607.
	Pressure, psia	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
	Temperature, F	154.6	151.4	108.9	115.3	114.6	106.0	105.3	105.1	105.0	112.6	109.2	142.8	138.1
	Enthalpy, Btu/lb	123.20	119.95	77.54	83.89	83.22	74.62	73.95	73.72	73.68	81.25	77.89	111.42	106.64
Stack Exhaust	Temperature, F	211.1	215.1	195.4	197.1	203.2	199.8	206.3	204.0	198.2	201.3	194.8	207.4	201.0
Steam Turbine Generator														
Main Steam Throttle Conditions	Flowrate, lb/h	1,169,554.	809,842.	1,168,612.	1,168,228.	823,381.	1,179,567.	836,396.	720,228.	645,555.	708,548.	642,529.	673,397.	625,746.
	Pressure, psia	1,909.1	1,338.5	1,907.7	1,907.1	1,360.5	1,908.2	1,358.7	1,154.1	1,039.6	1,153.8	1,053.8	1,108.3	1,037.1
	Temperature, F	1,050.0	1,049.9	1,050.0	1,050.0	1,050.0	1,029.9	1,009.7	966.3	970.6	1,003.7	1,015.3	1,027.2	1,040.7
	Enthalpy, Btu/lb	1,508.04	1,524.27	1,508.11	1,508.10	1,523.68	1,495.74	1,500.16	1,481.33	1,487.53	1,502.93	1,512.54	1,517.70	1,527.39
HPT Exit	Flowrate, lb/h	1,147,764.	794,754.	1,146,838.	1,146,461.	808,038.	1,157,586.	820,812.	706,808.	633,526.	695,346.	630,558.	660,850.	614,088.
	Pressure, psia	425.2	350.7	422.0	484.1	358.2	490.6	365.4	314.5	280.5	307.7	277.9	291.2	269.9
	Temperature, F	647.7	690.8	646.2	677.5	691.8	664.0	663.3	632.7	635.3	658.7	666.9	675.2	685.0
	Enthalpy, Btu/lb	1,332.90	1,361.22	1,332.26	1,345.97	1,361.29	1,337.85	1,345.42	1,332.09	1,335.77	1,346.55	1,352.71	1,356.31	1,362.70
Cold Reheat Steam	Flowrate, lb/h	1,147,764.	794,754.	1,146,838.	1,146,461.	808,038.	1,157,586.	820,812.	706,808.	633,526.	695,346.	630,558.	660,850.	614,088.
	Pressure, psia	425.2	350.7	422.0	484.1	358.2	490.6	365.4	314.5	280.5	307.7	277.9	291.2	269.9
	Temperature, F	647.7	690.8	646.2	677.5	691.8	664.0	663.3	632.7	635.3	658.7	666.9	675.2	685.0
	Enthalpy, Btu/lb	1,332.90	1,361.22	1,332.26	1,345.97	1,361.29	1,337.85	1,345.42	1,332.09	1,335.77	1,346.55	1,352.71	1,356.31	1,362.70
IPT Throttle Steam	Flowrate, lb/h	1,097,184.	937,961.	1,086,450.	1,275,568.	961,239.	1,308,739.	996,003.	872,531.	775,768.	840,699.	755,128.	787,757.	725,772.
	Pressure, psia	339.1	288.3	335.9	392.4	294.5	397.5	300.7	259.6	231.5	253.7	229.0	239.8	222.1
	Temperature, F	1,050.1	1,041.0	1,050.1	1,047.0	1,031.9	1,012.7	992.3	950.8	955.8	987.3	999.1	1,010.4	1,024.0
	Enthalpy, Btu/lb	1,551.69	1,548.26	1,551.78	1,548.61	1,543.23	1,530.12	1,522.10	1,501.52	1,505.01	1,520.83	1,527.80	1,533.40	1,541.05
LP Admission Steam #1	Flowrate, lb/h	117,676.	146,330.	97,544.	96,549.	137,793.	109,167.	152,698.	136,766.	116,492.	131,546.	110,140.	132,093.	113,560.
	Pressure, psia	56.9	50.6	55.4	63.8	51.1	65.2	52.7	45.7	40.4	44.6	39.8	42.5	38.9
	Temperature, F	579.0	545.6	586.2	585.3	553.0	589.3	555.2	542.4	532.0	537.8	529.3	527.7	522.2
	Enthalpy, Btu/lb	1,322.15	1,306.32	1,325.83	1,324.76	1,309.88	1,326.66	1,310.82	1,305.15	1,300.53	1,303.00	1,299.27	1,298.25	1,295.89

Table I-1
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

Case Description		1 100% Load STIG Hot Day Duct Firing On	2 100% Load Hot Day Duct Firing Off	3 100% Load STIG Avg Ambient Duct Firing On	4 100% Load Avg Ambient Duct Firing On	5 100% Load Avg Ambient Duct Firing Off	6 100% Load Cold Day Duct Firing On	7 100% Load Cold Day Duct Firing Off	8 85% Load Cold Day Duct Firing Off	9 70% Load Cold Day Duct Firing Off	10 85% Load Avg Ambient Duct Firing Off	11 70% Load Avg Ambient Duct Firing Off	12 85% Load Hot Day Duct Firing Off	13 70% Load Hot Day Duct Firing Off
Image File		NPE501FHotDayFireSTIG.img	NPE501FHotDay.img	NPE501FAvgFireSTIG.img	NPE501FAvgFire.img	NPE501FAvgDay.img	NPE501FColdFire.img	NPE501FColdDay.img	NPE501FColdDay85PL.img	NPE501FColdDay70PL.img	NPE501FAvgDay85PL.img	NPE501FAvgDay70PL.img	NPE501FHotDay85PL.img	NPE501FHotDay70PL.img
Run Date		05/23/01pcNT	05/28/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT	05/29/01pcNT
Ambient Temperature		101 F	101 F	51.1 F	51.1 F	51.1 F	-20 F	-20 F	-20 F	-20 F	51.1 F	51.1 F	101 F	101 F
Number of CTG/HRSG Units Operating		2	2	2	2	2	2	2	2	2	2	2	2	2
CTG Model		SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F	SWPC 501F
CTG Fuel		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of base load)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	85.00%	70.00%	85.00%	70.00%	85.00%	70.00%
CTG Evaporative Cooler		On	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
HRSG Firing		Fired	Unfired	Fired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
HRSG Model		Design: 1815 psia Maximum STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure	Design: 1815 psia STG Throttle Pressure
STG Output		193.6 MW	153.3 MW	220.9 MW	242.2 MW	180.8 MW	243.8 MW	184.2 MW	155.6 MW	138.1 MW	152.3 MW	137.9 MW	127.3 MW	119.6 MW
STG Throttle Conditions, psia/F		1909P/1050T	1339P/1050T	1908P/1050T	1907P/1050T	1361P/1050T	1908P/1030T	1359P/1010T	1154P/966T	1040P/971T	1154P/1004T	1054P/1015T	1108P/1027T	1037P/1041T
STG Hot Reheat Conditions, psia/F		339P/1050T	288P/1041T	336P/1050T	392P/1047T	295P/1032T	398P/1013T	301P/992T	260P/951T	232P/956T	254P/987T	229P/999T	240P/1010T	222P/1024T
Condenser Pressure		7 in HgA	6.3 in HgA	2 in HgA	2.3 in HgA	2.3 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	1.75 in HgA	2.19 in HgA	1.98 in HgA	5.09 in HgA	4.48 in HgA
Steam Turbine Generator Continued														
LPT1 Inlet	Flowrate, lb/h	1,227,426.	1,091,575.	1,196,647.	1,383,257.	1,106,411.	1,429,008.	1,156,008.	1,015,467.	897,861.	978,479.	870,999.	925,870.	844,989.
	Pressure, psia	55.8	49.6	54.3	62.5	50.1	63.9	51.7	44.8	39.6	43.7	39.0	41.7	38.2
	Temperature, F	591.6	590.3	589.0	583.6	583.5	561.7	559.2	531.5	532.3	554.5	559.8	569.8	576.6
	Enthalpy, Btu/lb	1,328.44	1,328.22	1,327.27	1,324.01	1,324.83	1,313.18	1,312.87	1,299.89	1,300.75	1,311.18	1,314.09	1,318.79	1,322.33
LP Turbine Exhaust	Flowrate, lb/h	1,227,454.	1,091,600.	1,196,674.	1,383,288.	1,106,436.	1,429,041.	1,156,034.	1,015,490.	897,882.	978,502.	871,019.	925,891.	845,008.
	Pressure, psia	3.438	3.094	0.982	1.130	1.130	0.860	0.860	0.860	0.860	1.076	0.972	2.500	2.200
	Pressure, in HgA	7.000	6.299	1.999	2.301	2.301	1.751	1.751	1.751	1.751	2.191	1.979	5.090	4.479
	Temperature, F	188.9	192.0	101.1	105.9	105.9	96.7	96.7	96.7	96.7	104.2	100.8	170.0	166.2
UEEP	Enthalpy, Btu/lb	1,144.12	1,145.68	1,058.42	1,056.58	1,064.13	1,047.31	1,049.33	1,045.30	1,049.65	1,060.66	1,063.07	1,135.86	1,134.30
Generator	Gross Output, kW	193,590.	153,250.	220,920.	242,170.	180,760.	243,770.	184,230.	155,640.	138,110.	152,310.	137,880.	127,270.	119,550.
Condenser Duty	Heat Duty,MBtu/h	1,248.63	1,130.50	1,180.29	1,360.95	1,097.01	1,405.91	1,139.75	997.16	885.68	968.50	867.30	957.65	876.89
Miscellaneous														
LP EVAP Water Outlet	Flowrate, lb/h	766,536.	568,525.	770,755.	741,883.	583,353.	758,091.	599,722.	529,584.	471,183.	511,562.	458,910.	479,408.	439,604.
	Pressure, psia	67.4	64.4	64.2	72.4	63.9	74.7	67.2	58.8	51.6	57.1	50.3	55.2	49.9
	Temperature, F	300.4	297.4	297.2	305.2	296.9	307.4	300.2	291.4	283.0	289.5	281.4	287.3	280.8
	Enthalpy, Btu/lb	270.19	267.07	266.87	275.12	266.55	277.36	269.99	260.85	252.29	258.93	250.68	256.71	250.07
IP BFP Discharge	Flowrate, lb/h	766,536.	568,525.	770,755.	741,883.	583,353.	758,091.	599,722.	529,584.	471,183.	511,562.	458,910.	479,408.	439,604.
	Pressure, psia	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
	Temperature, F	301.4	298.4	298.2	306.2	297.9	308.4	301.3	292.4	284.0	290.5	282.4	288.3	281.8
	Enthalpy, Btu/lb	272.22	269.12	268.91	277.14	268.59	279.37	272.03	262.90	254.37	260.99	252.76	258.78	252.15
HP BFP Discharge	Flowrate, lb/h	590,377.	408,942.	589,996.	589,708.	415,847.	595,551.	422,422.	363,752.	326,038.	357,851.	324,510.	340,098.	316,033.
	Pressure, psia	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0
	Temperature, F	304.7	301.7	301.5	309.6	301.2	311.8	304.5	295.5	287.1	293.7	285.5	291.5	284.9
	Enthalpy, Btu/lb	278.75	275.63	275.43	283.69	275.11	285.92	278.55	269.40	260.83	267.48	259.22	265.26	258.61
HP Evaporator Blowdown (each unit)	Flowrate, lb/h	5,600.	4,019.	5,690.	5,591.	4,157.	5,768.	4,224.	3,638.	3,260.	3,579.	3,245.	3,401.	3,160.
% Blowdown		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
IP Evaporator Blowdown (each unit)	Flowrate, lb/h	733.	723.	807.	652.	774.	763.	885.	837.	718.	734.	629.	641.	564.
% Blowdown		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
LP Evaporator Blowdown (each unit)	Flowrate, lb/h	338.	482.	248.	241.	449.	304.	523.	537.	461.	457.	385.	443.	388.
% Blowdown		1%	1%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Cycle Make Up Water (total for all units)	Flowrate, lb/h	242,481.	10,449.	253,769.	12,968.	10,759.	13,670.	11,264.	10,022.	8,880.	9,539.	8,518.	8,969.	8,225.
	Temperature, F	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Notes:

1. The combustion turbine generator (CTG) performance is based on client supplied CTG performance.
2. The CTG gas was assumed to be natural gas with a lower heating value of 20,890 Btu/lb.
3. Cycle consists of two blocks of 2x1 SWPC 501F combined cycles
4. Cycle makeup water temperature is assumed to be 70 F.
5. HRSG designed unfired to ambient conditions of 39°F, 60 %RH without chilling.
6. No Boiler Feed Pump efficiency curves were used and BFP outlet pressure was assumed to be constant.
7. Steam Turbine Generator maximum throttle pressure assumed to be 5% over design pressure.
8. 1% HRSG blowdown included.
9. This performance is an estimate and can not be guaranteed.

Table I-2
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

CTG Model Diluent/NOx Emission Rate CTG Fuel Type CTG Performance Reference HRSG Firing	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired
Ambient Temperature, F	101	101	51.1	51.1	51.1	-20	-20	-20	-20	51.1	51.1	101	101
Ambient Relative Humidity, %	18	18	58	58	58	80	80	80	80	58	58	18	18
CTG Compressor Inlet Temperature, F	72.76521579	72.76521579	51.1	51.1	51.1	-20	-20	-20	-20	51.1	51.1	101	101
CTG Compr. Inlet Relative Humidity, %	77.98091836	77.98091836	58	58	58	80	80	80	80	58	58	18	18
Atmospheric Pressure, psia	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340	14.340
Evaporative Cooling Included?	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	100%	100%	100%	85%	70%	85%	70%	85%	70%
Gross CTG Output, kW	189,890	168,850	201,690	181,480	181,480	209,790	209,790	181,430	149,210	154,090	126,660	128,800	105,810
Gross CTG Heat Rate, Btu/kWh (LHV)	9,003	9,350	8,888	9,205	9,205	8,935	8,935	9,109	9,500	9,460	9,931	9,901	10,604
CTG Heat Input, MBtu/h (LHV)	1,709.58	1,578.75	1,792.62	1,670.52	1,670.52	1,874.47	1,874.47	1,652.65	1,417.50	1,457.69	1,257.86	1,275.25	1,122.01
CTG Heat Input, MBtu/h (HHV)	1,897.28	1,752.09	1,989.44	1,853.93	1,853.93	2,080.28	2,080.28	1,834.10	1,573.13	1,617.74	1,395.97	1,415.27	1,245.20
CTG Fuel Flow, lb/h	81,840	75,570	85,810	79,970	79,970	89,730	89,730	79,110	67,860	69,780	60,210	61,050	53,710
CTG Water Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0
CTG Steam Injection Flow, lb/h	114,570	0	120,140	0	0	0	0	0	0	0	0	0	0
Injection Ratio	1.400	0.000	1.400	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CTG Exhaust Flow, lb/h	3,530,215	3,409,855	3,729,530	3,604,060	3,604,060	3,955,835	3,955,835	3,707,100	3,271,185	3,379,295	2,989,455	3,069,530	2,783,300
CTG Exhaust Temperature, F	1,116	1,116	1,100	1,098	1,098	1,052	1,052	996	997	1,037	1,046	1,061	1,073
CTG Exhaust Analysis (Volume Basis - Wet)													
Ar	0.87%	0.92%	0.89%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.93%	0.94%
CO2	3.91%	3.82%	3.90%	3.84%	3.84%	3.93%	3.93%	3.70%	3.60%	3.58%	3.49%	3.44%	3.34%
H2O	14.63%	9.55%	13.32%	8.25%	8.25%	7.74%	7.74%	7.29%	7.09%	7.73%	7.57%	7.93%	7.73%
N2	69.60%	73.48%	70.61%	74.52%	74.52%	74.99%	74.99%	75.16%	75.24%	74.72%	74.79%	74.47%	74.54%
O2	10.99%	12.23%	11.28%	12.46%	12.46%	12.40%	12.40%	12.90%	13.12%	13.03%	13.22%	13.23%	13.45%
SO2	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00004%	0.00004%	0.00004%	0.00004%	0.00004%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)													
NOx, ppmvd @15% O2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, lb/h as NO2	178.0	164.3	186.6	173.9	173.9	195.1	195.1	172.0	147.6	151.8	130.9	132.8	116.8
CO, ppmvd	27.1	25.0	26.6	24.8	24.8	25.2	25.2	23.6	22.9	22.9	22.3	22.1	21.4
CO, lb/h	82.6	76.2	86.6	80.7	80.7	90.5	90.5	79.8	68.5	70.4	60.8	61.6	54.2
SO2, ppmvd (with no conversion to H2SO4)	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
SO2, lb/h (with no conversion to H2SO4)	4.0	3.6	4.1	3.9	3.9	4.3	4.3	3.8	3.3	3.4	2.9	2.9	2.6
UHC, ppmvw	5.6	5.4	5.6	5.5	5.5	5.6	5.6	5.3	5.1	5.1	5.0	4.9	4.7
UHC, lb/h as CH4	11.4	10.5	11.9	11.1	11.1	12.4	12.4	11.0	9.4	9.7	8.3	8.5	7.4
VOC percentage of UHC	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
VOC, ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2
VOC, lb/h as CH4	2.8	2.6	3.0	2.8	2.8	3.1	3.1	2.7	2.4	2.4	2.1	2.1	1.9
Particulates, lb/h (front only), excluding 2(NH4(SO4))	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Particulates, lb/h (front and back), excluding 2(NH4(SO4))	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
PM10, lb/h (front only), excluding 2(NH4(SO4))	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
PM10, lb/h (front and back), excluding 2(NH4(SO4))	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

Table I-2
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

CTG Model	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD
Diluent/NOx Emission Rate	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Performance Reference	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted
HRSG Firing	Fired NG	Unfired	Fired NG	Fired NG	Unfired	Fired NG	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Emissions (at CTG exhaust flange)													
NOx, ppmvd @15% O2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, ppmvd @ 15% O2	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, lb/h as NO2	178.0	164.3	186.6	173.9	173.9	195.1	195.1	172.0	147.6	151.8	130.9	132.8	116.8
NOx, lb/MBtu (LHV)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
NOx, lb/MBtu (HHV)	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
CO, ppmvd	27.1	25.0	26.6	24.8	24.8	25.2	25.2	23.6	22.9	22.9	22.3	22.1	21.4
CO, ppmvw	23.2	22.6	23.1	22.7	22.7	23.3	23.3	21.9	21.3	21.2	20.6	20.4	19.8
CO, ppmvd @ 15% O2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO, ppmvd @ 15% O2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO, lb/h	82.6	76.2	86.6	80.7	80.7	90.5	90.5	79.8	68.5	70.4	60.8	61.6	54.2
CO, lb/MBtu (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO, lb/MBtu (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2, ppmvd (with no conversion to H2SO4)	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
SO2, ppmvw (with no conversion to H2SO4)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
SO2, ppmvd @ 15% O2 (with no conversion to H2SO4)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SO2, ppmvd @ 15% O2 (with no conversion to H2SO4)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SO2, lb/h (with no conversion to H2SO4)	4.0	3.6	4.1	3.9	3.9	4.3	4.3	3.8	3.3	3.4	2.9	2.9	2.6
SO2, lb/MBtu (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2, lb/MBtu (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UHC, ppmvd	6.5	6.0	6.4	6.0	6.0	6.1	6.1	5.7	5.5	5.5	5.4	5.3	5.1
UHC, ppmvw	5.6	5.4	5.6	5.5	5.5	5.6	5.6	5.3	5.1	5.1	5.0	4.9	4.7
UHC, ppmvd @ 15% O2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
UHC, ppmvd @ 15% O2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
UHC, lb/h as CH4	11.4	10.5	11.9	11.1	11.1	12.4	12.4	11.0	9.4	9.7	8.3	8.5	7.4
UHC, lb/MBtu as CH4 (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UHC, lb/MBtu as CH4 (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VOC percentage of UHC	0.2	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
VOC, ppmvd	1.6	1.5	1.6	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.3	1.3	1.3
VOC, ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2
VOC, ppmvd @ 15% O2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
VOC, ppmvd @ 15% O2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
VOC, lb/h as CH4	2.8	2.6	3.0	2.8	2.8	3.1	3.1	2.7	2.4	2.4	2.1	2.1	1.9
VOC, lb/MBtu as CH4 (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VOC, lb/MBtu as CH4 (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Particulates, lb/h (front only), excluding 2(NH4(SO4))	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Particulates, lb/h (front and back), excluding 2(NH4(SO4))	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Particulates, lb/MBtu (LHV) (front only)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Particulates, lb/MBtu (HHV) (front only)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM10, lb/h (front only), excluding 2(NH4(SO4))	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
PM10, lb/h (front and back), excluding 2(NH4(SO4))	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
PM10, lb/MBtu (LHV) (front and back)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM10, lb/MBtu (HHV) (front and back)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTG Fuel LHV, Btu/lb	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890	20,890
CTG Fuel HHV, Btu/lb	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184	23,184
HHV/LHV Ratio	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098	1.1098
CTG Fuel Composition (Ultimate Analysis by Weight)													
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%	73.14%
H2	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%	24.06%
N2	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%	1.55%
O2	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table I-2
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

CTG Model Diluent/NOx Emission Rate CTG Fuel Type CTG Performance Reference HRSG Firing	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired
CTG Wet (Total) Exhaust Gas Analysis													
Molecular Wt, lb/mol	27.72	28.27	27.86	28.41	28.41	28.48	28.48	28.51	28.52	28.45	28.46	28.41	28.42
Gas Constant, ft-lbf/lbm-R	55.734	54.655	55.448	54.376	54.376	54.254	54.254	54.200	54.176	54.314	54.294	54.378	54.354
Specific Volume, ft^3/lb	41.03	40.23	40.40	39.57	39.57	38.32	38.32	36.86	36.87	37.98	38.19	38.63	38.92
Exhaust Gas Flow, acfm	2,414,079	2,286,308	2,511,217	2,376,878	2,376,878	2,526,460	2,526,460	2,277,395	2,010,143	2,139,094	1,902,788	1,976,266	1,805,434
Specific Volume, scf/lb	13.69	13.42	13.62	13.35	13.35	13.32	13.32	13.31	13.30	13.34	13.33	13.35	13.35
Exhaust Gas Flow, scfm	805,477	762,671	846,603	801,903	801,903	878,195	878,195	822,358	725,113	751,330	664,157	682,970	619,284
Specific Volume, Nm3/kg	0.8086	0.7929	0.8044	0.7889	0.7889	0.7871	0.7871	0.7863	0.7860	0.7880	0.7877	0.7889	0.7886
Exhaust Gas Flow, Nm3/s	359.66	340.66	378.00	358.24	358.24	392.31	392.31	367.27	323.96	335.52	296.70	305.11	276.55
Duct Burner Heat Input, MBtu/h (LHV)	217.3	0.0	206.8	248.6	0.0	245.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	241.1	0.0	229.5	275.9	0.0	272.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Fuel Composition (Ultimate Analysis by Weight)													
Ar	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
C	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%	73.142%
H2	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%	24.063%
N2	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%	1.546%
O2	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%	1.246%
S	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%	0.002%
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%
Duct Burner NOx, lb/MBtu (HHV)	0.100	0.080	0.080	0.080	0.080	0.100	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
DB non-meth/non-eth VOC (as CH4), lb/MBtu (HHV)	0.025	0.024	0.024	0.024	0.024	0.025	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Duct Burner Particulate, lb/MBtu (HHV) (front only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, lb/MBtu (HHV) (front and back)	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Duct Burner PM10, lb/MBtu (HHV) (front only)	0.010	0.008	0.008	0.008	0.008	0.010	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Duct Burner PM10, lb/MBtu (HHV) (front and back)	0.020	0.016	0.016	0.016	0.016	0.020	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Duct Burner SO2, lb/h	0.251	0.000	0.239	0.288	0.000	0.284	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DB NOx, lb/h	24.1	0.0	18.4	22.1	0.0	27.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB CO, lb/h	24.1	0.0	23.0	27.6	0.0	27.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB UHC (as CH4), lb/h	14.5	0.0	13.8	16.6	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB VOC (as CH4), lb/h	6.0	0.0	5.5	6.6	0.0	6.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB Particulate, lb/h (front only)	2.4	0.0	2.3	2.8	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB Particulate, lb/h (front and back)	4.8	0.0	4.6	5.5	0.0	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB PM10, lb/h (front only)	2.4	0.0	1.8	2.2	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB PM10, lb/h (front and back)	4.8	0.0	3.7	4.4	0.0	5.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Exhaust Analysis (Volume Basis - Wet)													
Ar	0.87%	0.92%	0.88%	0.93%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.93%	0.94%
CO2	4.39%	3.82%	4.34%	4.39%	3.84%	4.43%	3.93%	3.70%	3.60%	3.58%	3.49%	3.44%	3.34%
H2O	15.53%	9.55%	14.14%	9.31%	8.25%	8.71%	7.74%	7.29%	7.09%	7.73%	7.57%	7.93%	7.73%
N2	69.26%	73.48%	70.30%	74.10%	74.52%	74.61%	74.99%	75.16%	75.24%	74.72%	74.79%	74.47%	74.54%
O2	9.96%	12.23%	10.34%	11.27%	12.46%	11.32%	12.40%	12.90%	13.12%	13.03%	13.22%	13.23%	13.45%
SO2	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00005%	0.00004%	0.00004%	0.00004%	0.00004%	0.00004%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table I-2
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

CTG Model Diluent/NOx Emission Rate CTG Fuel Type CTG Performance Reference HRSG Firing	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Fired NG	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired	W501FD Dry Low NOx Natural Gas B&V Adjusted Unfired
Emissions (at Stack exit)													
NOx, ppmvd @15% O2 w/o SCR	25.3	25.0	24.7	24.7	25.0	25.3	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, lb/h as NO2 w/o SCR	202.1	164.3	205.0	196.0	173.9	222.4	195.1	172.0	147.6	151.8	130.9	132.8	116.8
NOx, ppmvd @15% O2 w/ SCR	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NOx, lb/h as NO2 w/ SCR	19.1	15.7	19.8	19.0	16.6	21.0	18.6	16.4	14.1	14.5	12.5	12.6	11.1
NH3, ppmvd @15% O2 w/o SCR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH3, lb/h w/o SCR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH3 slip, ppmvd @15% O2 w/ SCR	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h w/ SCR	28.3	23.2	29.4	28.2	24.5	31.1	27.5	24.3	20.8	21.4	18.5	18.7	16.5
CO, ppmvd w/o Catalyst	35.2	25.0	33.9	33.4	24.8	33.0	25.2	23.6	22.9	22.9	22.3	22.1	21.4
CO, ppmvw w/o Catalyst	29.8	22.6	29.1	30.3	22.7	30.1	23.3	21.9	21.3	21.2	20.6	20.4	19.8
CO, ppmvd @ 15% O2 w/o Catalyst	22.9	20.0	22.7	23.4	20.0	23.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO, lb/h w/o Catalyst	106.7	76.2	109.5	108.3	80.7	117.8	90.5	79.8	68.5	70.4	60.8	61.6	54.2
CO, ppmvd w/ Catalyst	7.0	5.0	6.8	6.7	5.0	6.6	5.0	4.7	4.6	4.6	4.5	4.4	4.3
CO, ppmvw w/ Catalyst	6.0	4.5	5.8	6.1	4.5	6.0	4.7	4.4	4.3	4.2	4.1	4.1	4.0
CO, ppmvd @ 15% O2 w/ Catalyst	4.6	4.0	4.5	4.7	4.0	4.6	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/h w/ Catalyst	21.3	15.2	21.9	21.7	16.1	23.6	18.1	16.0	13.7	14.1	12.2	12.3	10.8
SO2, ppmvd (with no conversion to H2SO4)	0.64	0.52	0.62	0.60	0.52	0.60	0.53	0.49	0.48	0.48	0.47	0.46	0.45
SO2, ppmvw (with no conversion to H2SO4)	0.54	0.47	0.54	0.54	0.48	0.55	0.49	0.46	0.45	0.44	0.43	0.43	0.41
SO2, lb/h (with no conversion to H2SO4)	4.45	3.65	4.62	4.44	3.86	4.90	4.33	3.82	3.28	3.37	2.91	2.95	2.59
Total S in Exhaust Gas, lb/h	2.23	1.83	2.31	2.22	1.93	2.45	2.17	1.91	1.64	1.69	1.45	1.47	1.30
Exhaust Gas SO3 (converted from SO2), ppmvw	0.09	0.09	0.09	0.10	0.09	0.10	0.09	0.09	0.09	0.09	0.08	0.08	0.08
Exhaust Gas SO3 (converted from SO2), ppmvd	0.11	0.10	0.11	0.11	0.10	0.11	0.10	0.09	0.09	0.09	0.09	0.09	0.09
Exhaust Gas SO3 (converted from SO2), lb/h	0.96	0.86	1.01	1.01	0.91	1.11	1.02	0.92	0.79	0.81	0.70	0.71	0.63
Exhaust Gas H2SO4 (100% converted from SO3), lb/h	1.18	1.05	1.24	1.23	1.12	1.36	1.25	1.12	0.97	0.99	0.86	0.87	0.77
Remaining SO2 in Exhaust Gas, ppmvw	0.45	0.38	0.44	0.44	0.39	0.45	0.39	0.37	0.36	0.36	0.35	0.34	0.33
Remaining SO2 in Exhaust Gas, ppmvd	0.53	0.42	0.52	0.49	0.42	0.49	0.43	0.40	0.39	0.39	0.38	0.37	0.36
Remaining SO2 in Exhaust Gas, lb/h	3.68	2.96	3.81	3.63	3.13	4.01	3.51	3.09	2.64	2.72	2.34	2.38	2.09
NOTE: UHC and VOC calculations do NOT include the effect of any oxidation in the CO catalyst.													
UHC, ppmvd	14.9	6.0	13.9	14.9	6.0	14.1	6.1	5.7	5.5	5.5	5.4	5.3	5.1
UHC, ppmvw	12.6	5.4	11.9	13.5	5.5	12.9	5.6	5.3	5.1	5.1	5.0	4.9	4.7
UHC, ppmvd @ 15% O2	9.7	4.8	9.3	10.4	4.8	9.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
UHC, lb/h as CH4	25.8	10.5	25.7	27.7	11.1	28.8	12.4	11.0	9.4	9.7	8.3	8.5	7.4
VOC, ppmvd	5.1	1.5	4.6	5.1	1.5	4.9	1.5	1.4	1.4	1.4	1.3	1.3	1.3
VOC, ppmvw	4.3	1.4	3.9	4.6	1.4	4.4	1.4	1.3	1.3	1.3	1.2	1.2	1.2
VOC, ppmvd @ 15% O2	3.3	1.2	3.1	3.5	1.2	3.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2
VOC, lb/h as CH4	8.9	2.6	8.5	9.4	2.8	9.9	3.1	2.7	2.4	2.4	2.1	2.1	1.9
NOTE: Particulate and PM10 calculations do NOT include the effect of any SO2 conversions in the SCR catalyst.													
Particulates, lb/h (front only), excluding 2(NH4(SO4))	12.4	10.0	12.3	12.8	10.0	12.7	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Particulates, lb/h (front and back), excluding 2(NH4(SO4))	24.8	20.0	24.6	25.5	20.0	25.4	20.0	20.0	20.0	20.0	20.0	20.0	20.0
PM10, lb/h (front only), excluding 2(NH4(SO4))	12.4	10.0	11.8	12.2	10.0	12.7	10.0	10.0	10.0	10.0	10.0	10.0	10.0
PM10, lb/h (front and back), excluding 2(NH4(SO4))	24.8	20.0	23.7	24.4	20.0	25.4	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Particulates, lb/h (front only), including 2(NH3(SO4))	14.0	11.4	14.0	14.4	11.5	14.6	11.7	11.5	11.3	11.3	11.2	11.2	11.0
Particulates, lb/h (front and back), including 2(NH3(SO4))	26.4	21.4	26.3	27.2	21.5	27.3	21.7	21.5	21.3	21.3	21.2	21.2	21.0
PM10, lb/h (front only), including 2(NH3(SO4))	14.0	11.4	13.5	13.9	11.5	14.6	11.7	11.5	11.3	11.3	11.2	11.2	11.0
PM10, lb/h (front and back), including 2(NH3(SO4))	26.4	21.4	25.3	26.1	21.5	27.3	21.7	21.5	21.3	21.3	21.2	21.2	21.0

Table I-2
Starbuck Power Project
Expected Combustion Turbine and HRSG Emissions

CTG Model	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD	W501FD
Diluent/NOx Emission Rate	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx	Dry Low NOx
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Performance Reference	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted	B&V Adjusted
HRSG Firing	Fired NG	Unfired	Fired NG	Fired NG	Unfired	Fired NG	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
NOTE: SO2 converted to H2SO4 (assumed).	17.3%	18.8%	17.5%	18.2%	18.9%	18.2%	18.9%	19.2%	19.3%	19.3%	19.4%	19.4%	19.5%
Remaining SO2 in Exhaust Gas, lb/h	3.68	2.96	3.81	3.63	3.13	4.01	3.51	3.09	2.64	2.72	2.34	2.38	2.09
Exhaust Gas H2SO4 (100% converted from SO3), lb/h	1.18	1.05	1.24	1.23	1.12	1.36	1.25	1.12	0.97	0.99	0.86	0.87	0.77
Exhaust Gas 2(NH3(SO4)) 100% from SO3, lb/h	1.58	1.41	1.67	1.66	1.50	1.84	1.69	1.51	1.30	1.34	1.16	1.18	1.04
Stack Exit Temperature, F	227	227	221	211	214	228	227	227	227	227	227	227	227
Stack Diameter, ft (estimated)	19	19	19	19	19	19	19	19	19	19	19	19	19
Stack Flow, lb/h	3,540,615	3,409,855	3,739,430	3,615,960	3,604,060	3,967,585	3,955,835	3,707,100	3,271,185	3,379,295	2,989,455	3,069,530	2,783,300
Stack Flow, scfm	809,031	762,671	850,097	806,359	801,903	882,788	878,195	822,358	725,113	751,330	664,157	682,970	619,284
Stack Flow, acfm	1,095,820	1,032,618	1,141,149	1,066,708	1,065,600	1,197,549	1,189,388	1,113,366	982,446	1,017,168	899,328	924,952	838,237
Stack Exit Velocity, ft/s	64.4	60.7	67.1	62.7	62.6	70.4	69.9	65.4	57.8	59.8	52.9	54.4	49.3
w/ SCR													
NOx Removed, lb/h as NO2	158.9	148.7	166.8	154.9	157.4	174.1	176.6	155.7	133.5	137.3	118.5	120.1	105.7
NOx Removed, percent	89.3%	90.5%	89.4%	89.1%	90.5%	89.2%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
NH3 Reacted, lb/h (1:1 stoichiometric ratio)	58.7	55.0	61.6	57.2	58.2	64.3	65.2	57.5	49.3	50.7	43.8	44.4	39.1
NH3 Slip, lb/h	28.3	23.2	29.4	28.2	24.5	31.1	27.5	24.3	20.8	21.4	18.5	18.7	16.5
Total NH3 Consumption, lb/h	87.0	78.1	91.0	85.4	82.7	95.5	92.8	81.8	70.2	72.1	62.2	63.1	55.5

Notes:
1. Duct Burner fuel is based on site natural gas analysis provided by KN Energy.
2. Particulate values do not contain cayalsyt fines or other entrained particulate matter.
3. Stack VOC emissions do not include effects reduction due to CO catalyst.
4. SCR controls NOx to 3.5 ppmvd @ 15% O2.
5. Emissions calculation do not include heavy particles such as lead, mercury, aldehydes, etc.
6. Changes in fuel constituents from those provided and indicated in this table may change VOC, UHC, NOx, SOx, and other predicted emission levels.
7. Fuel sulfur content is 0.75 grains per 100 scf.