STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL
DRAFT FACT SHEET FOR**{**PRIVATE **}**
PREVENTION OF SIGNIFICANT DETERIORATION
Sumas Energy 2 Generation Facility Project
Sumas, Washington
September 28, 2001

Important Note: The following is a DRAFT Fact Sheet to accompany a DRAFT Notice of Construction/Prevention of Significant Deterioration (NOC/PSD) Permit for the proposed Sumas Energy 2 Generation Facility. This Draft Fact Sheet was written on behalf of the Energy Facility Site Evaluation Council (EFSEC) by its contractor, the Department of Ecology, Air Quality Program.

EFSEC and EPA rules (Chapter 463-39 Washington Administrative Code and 40 CFR 51.166(q)) and 40 CFR 124 subparts A and C) require EFSEC to draft a PSD Permit and Fact Sheet. The Fact Sheet discusses the project and the issues considered in preparing the draft Permit. The Fact Sheet developed for this draft Permit is available to anyone who wishes a copy. THE ISSUANCE OF THIS DRAFT FACT SHEET AND DRAFT PSD PERMIT SHOULD IN NO WAY BE INTERPRETED TO REPRESENT CONCLUSIONS, CONDITIONS OR RECOMMENDATIONS TO THE GOVERNOR OF WASHINGTON STATE DRAWN BY THE ENERGY FACILITY SITE EVALUATION COUNCIL.

1. INTRODUCTION

1.1 THE PSD PROCESS

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of the Federal Regulations (CFR), 40 CFR Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality to that which is not considered "significant" as defined by the Federal Regulations listed above. It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

The Washington State Energy facility Site Evaluation Council (EFSEC) is the PSD permitting authority for energy facilities greater than 350 MW sited in the state of Washington per Chapter 463-39 of the Washington Administrative Code (WAC).

1.2 THE PROJECT

Sumas Energy 2, Inc., (SE2) proposes to construct and operate the Sumas Energy 2 Generation Facility (SE2GF), an electrical generating facility located in Sumas, Washington. SE2 would own and operate SE2GF including activities related to obtaining permits and other required approvals. SE2GF would be a “merchant” plant, selling power wherever there is a market. The SE2GF would be constructed within the City of Sumas, in Whatcom County, Washington. The proposed project site is located in an industrial zone in the City of Sumas, about one-half mile south of the international border and immediately north of the Sumas Cogeneration Company LP No. 1 Generation Facility (SCCLP), a 125 mw power station. The approximately 37-acre property, which includes the site, consists of a 26-acre open field used for agriculture and a 10.6 acre forested wetland, which would be preserved as an element of site planning.

1.2.1 General Description

The SE2GF would be a combined-cycle facility using natural gas as the only fuel source for the combustion turbines[1]. The facility design includes two separate but identical combustion turbines, one steam turbine, two generators and two heat recovery steam generators (HRSG). Each HRSG would include a duct burner. Each combustion turbine would discharge hot exhaust gases to the HRSG, which produces reheat steam flows to high, intermediate and low pressure sections of the steam turbines. The nominal capacity of each combustion and steam turbine set would be 334.5 MW yielding a total nominal plant capacity of 669 MW.

1.2.2 Fuel Source and Transport

At a 97 percent capacity factor, SE2GF would generate approximately 5.7 million megawatt hours of electricity annually and approximately 170 million megawatt hours of electricity over a 30 year operational life. To achieve this generation, SE2GF would consume approximately 112 million cubic feet of natural gas daily. The facility would operate at an overall thermal efficiency of 53.5%. The natural gas would be produced in Canada, and delivered through a new 4.5 mile pipeline built parallel to an existing pipeline that delivers natural gas to the existing Sumas Cogeneration Facility. The pipeline border crossing is regulated by the Federal Energy Regulatory Commission (FERC) and would be subject to environmental review under the National Energy Policy Act and federal safety standards of the Office of Pipeline Safety. The new 4.5 mile natural gas pipeline, excluding the border crossing, is regulated by EFSEC and is subject to environmental review under the Washington State Environmental Policy Act (SEPA) and EFSEC rules and regulations. The environmental impacts of this natural gas pipeline were assessed in the SE2GF Final Environmental Impact Statement issued by EFSEC in February 2001.

1.2.3 Power Transmission

The electrical energy produced by SE2GF would be transmitted to British Columbia Hydro (BCH) through a new switchyard located at the project site and a 5.9 mile transmission line to the Canadian electric grid at BCH’s Clayburn substation located outside Abbotsford, B.C. The

[1] Diesel-powered internal combustion engines for an emergency generator and for driving fire-suppression water pumps are included in the permit. Very low sulfur content oil is required.

transmission line border crossing is regulated by the Federal Energy Regulatory Commission (FERC) and would be subject to environmental review under the National Energy Policy Act. The new 5.9 mile transmission line, excluding the border crossing, is regulated by EFSEC and is subject to environmental review under the Washington State Environmental Policy Act (SEPA) and EFSEC rules and regulations. This activity has no impact on the PSD permit. The environmental impacts of the U.S. portion of this transmission line were assessed in the SE2GF Final Environmental Impact Statement issued by EFSEC in February 2001.

1.2.4 Water Consumption

The City of Sumas would supply the water required by SE2GF (maximum 774 gallons per minute). The City of Sumas would not require expansion of any existing water right or a new water right, but may need to drill one or two additional wells to maximize use of the existing rights. The City of Sumas may need to make some modifications to its water system, such as, interties between the potable and industrial systems and various control valves. The City of Sumas would construct a pipeline to connect potable and industrial water to SE2GF. These activities would have no impact on this PSD permit.

1.2.5 Waste Water

The average total wastewater discharge from SE2GF is expected to be an average of 22 gpm. SE2 is proposing that combined wastewater discharge from both the proposed SE2GF and the existing Sumas Cogeneration Company LP No. 1 Generation Facility (SCCLP) would not exceed the discharge currently allowed from the SCCLP. The wastewater sources are cooling tower blowdown, reverse osmosis reject, demineralizer waste, polisher waste, and employee domestic waste. All wastewater will be discharged to the City of Sumas sewer system. SE2GF has received a Certificate of Water and Sewer Availability for up to 260 gpm. These activities would have no impact on this PSD permit.

1.2.6 Air Pollutant Emissions

1.2.6.1 General Description

The SE2GF facility would be a major new source of air pollution because it has the capacity to emit any one of nitrogen oxides (NO_x), volatile organic compounds (VOCs), or particulate matter (PM_{10})[1] at more than 100 tons per year. Some of the sulfur dioxide from the facility is expected

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[1] Potential to emit:

NO_x: 144.5 tons per year
CO: 88 tons per year
SO_x: 69 tons per year
VOCs: 153 tons per year
PM_{10}: 209 tons per year (filterable and condensable)
H_2SO_4 mist: 14.3 tons per year (13.5% molar conversion SO_2 to SO_3, fully hydrated)

to convert and hydrolyze to sulfuric acid mist[1]. Emissions of NO_x, VOCs, PM_{10}, SO_2/SO_3, and sulfuric acid mist at these levels are subject to regulation under the PSD program. The anticipated CO emission level is below PSD significance, but nonetheless subject to new source review under WAC 173-460-110 (new source review).

SE2GF would also emit toxic air pollutants. The sulfuric acid mist included as a criteria pollutant, above, is also a toxic air pollutant. Excess ammonia from NO_x reduction and some of the unburned hydrocarbons[1] are the other toxic air pollutants that would be emitted by SE2GF. Toxic air pollutants are regulated under Chapter 173-460 WAC (new source review regulations for toxic air pollutants).

1.2.6.2 National Ambient Air Quality Standards

The United States Environmental Protection Agency (EPA) and the Washington Department of Ecology (Ecology) have established ambient air quality standards (NAAQS and WAAQS, respectively). “Primary” standards apply to populated areas (Class II areas), and are designed to protect human health and safety. “Secondary” standards apply to sensitive areas (Class I areas), and are designed to protect soils and vegetation. The site of the proposed project is within a Class II area that is in attainment with regard to all pollutants regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The proposed site is 55 kilometers (km.) from the nearest Class I Area, North Cascades National Park, within 175 km. of four other Class I areas (Alpine Lakes Wilderness, Glacier Peak Wilderness, Olympic National Park, and Pasayten Wilderness), and within one-half mile of the Canadian border. Impacts of SE2GF on visibility, soils, and vegetation in Class I areas are discussed in Section 4.1, below.

Potential impacts are tested by modeling the predicted increase in ambient concentrations of the pollutants (NO_x, CO, SO_x, and PM_{10}) emitted by the new source, and comparing them to a maximum that is allowed (Class I or II increment). EPA has established no significant ambient impact concentration for ozone (VOCs). However, VOC emissions from SE2GF are expected to be high enough that an ambient impact analysis is required for ozone.

The modeled maximum criteria pollutant concentrations attributable to the operation of SE2GF are below the defined Class II significance levels for all pollutants on both short-term (24 hour average or less) and long-term (annual average) bases. As a result, under the requirements of state and federal regulations, the applicant is not required to model the cumulative impact of SE2GF along with that of existing sources in the vicinity of the SE2GF proposal.

Modeled pollutant concentration increases were determined for SE2GF alone for Class I areas within 175 kilometers. The modeled maximum criteria pollutant concentrations attributable to the operation of Sumas II are below the proposed Class I significance levels[2] for all pollutants on

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[1] Formaldehyde, toluene, xylene, and acetaldehyde constitute 95% of the potential 22 tons per year of unburned hydrocarbons. There are 139 tons per year of potential ammonia emissions.
[2] Class I significance levels are not codified, but have been proposed by the EPA to be used in a

both short-term (24 hour average or less) and long-term (annual average) bases. The ozone impact analysis performed to evaluate the contribution of the project in the adjoining Lower Fraser Valley indicated that "increases in ozone episode intensity … will be small and localized."[1] The Canadian agencies joint summary[2] concluded that "it is unlikely that the facility emissions will cause additional exceedances of the new Canada Wide Standard for ground level ozone … or result in an increase in ozone concentrations where (the standard) is already exceeded or … close to being exceeded." Both of these analyses were made using the higher emission levels estimated for the previous PSD permit application (January, 2000). The relevant pollutant emissions are slightly lower than in the current application.

1.2.6.3 Canadian National Ambient Air Quality Objectives and Canada-Wide Standards

Because the proposed facility is so close to the U.S. – Canada border, SE2 analyzed the pollutant emission impact of SE2GF relative to the Canada-Wide Standards[3] (CWS) and Canadian National Ambient Air Quality Objectives as well as the objectives established by British Columbia and the Greater Vancouver Regional District (GVRD). The area modeled included the Fraser Valley. The CWS are similar to the NAAQS and WAAQS in that they establish limits on ambient air pollutant concentrations that must not be exceeded. However, the CWS are targeted for phase in by 2010 whereas the NAAQS and WAAQS are currently fully applicable. The Canadian "objectives" are guidelines intended to assist Canadian federal, provincial, and local government in decision-making. There are three levels of Canadian objectives:

- Maximum desirable: Long-term goals that provide a basis for an anti-degradation policy for the unpolluted parts of Canada and for continuing development of control technology. The related pollutant concentrations are roughly equal to one-third to one-half the NAAQS.

- Maximum acceptable: Intended to provide adequate protection against adverse effects on humans and the environment. The related pollutant concentrations are roughly equal to the NAAQS.

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manner similar to those applicable to Class II areas (Federal Register, Vol. 61, No. 142, page 38292).

[1] Di Cenzo, Colin and Potter, Joanne, A Numerical Simulation of Impacts on Ambient Ground level Ozone Concentrations from the Proposed Sumas Energy 2, Inc. Power Generation Facility, Report 2000-001, Atmospheric Sciences Section, Environment Canada (January 31, 2000, Vancouver, BC), http://www.efsec.wa.gov/Sumas2/s2revjan00/s2gf_ozone.pdf

[2] Technical staff from the BC Ministry of Environment, lands, and Parks, Environment Canada - pacific and Yukon Region, and the Greater Vancouver Regional District, Sumas Energy 2 Generation Facility, Air Quality issue Summary, (September 11, 2000)

[3] Canada-Wide Standards for ozone, particulate matter (<2.5 micron diameter), mercury, and benzene were ratified by the Canadian federal government in June, 2000. CWS for several other environmental pollutants are in various stages of acceptance, endorsement, or ratification.

- Maximum tolerable: Time-based concentrations beyond which immediate action is required to protect public health.

The modeled maximum criteria pollutant concentrations that could result when background concentrations are combined with those from SE2GF are below the Maximum Desirable Air Quality Objectives.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1 DEFINITION and POLICY CONCERNING BACT

All new sources are required to utilize Best Available Control Technology (BACT). BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost effectiveness, economic, energy, environmental and other impacts (40 CFR 52.21(b)(12)).

The "top down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then tries to prove it technically infeasible or not economically justifiable. If proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology cannot be defeated, then it is determined to be BACT.

2.2 BACT ANALYSIS FOR CRITERIA POLLUTANTS

2.2.1 NITROGEN OXIDES CONTROL

Federal new source performance standards (NSPS) for stationary gas turbines (40 CFR 60.330 Subpart GG) limit NO_x from the proposed Westinghouse turbines to 159 parts per million by dry volume (ppmdv) corrected to 15 percent oxygen. SO_2 emissions are limited to 150 ppmdv, and the use of fuel containing more than 0.8 percent sulfur is prohibited. As will be shown in the following BACT discussion, the permitted emission concentrations for NO_x and SO_2 would be 2 ppmdv and 1 ppmdv, respectively. Natural gas would be SE2GF's only permitted fuel, and would have a maximum sulfur content of about 0.004%. Federal new source performance standards for electric utility steam generating units (40 CFR 60.40a Subpart Da) apply to the gas-fired duct burners in the proposed SE2GF system. Under this NSPS, particulate, sulfur dioxide and nitrogen dioxide emissions from the duct burners would be limited to 0.03, 0.2, and 0.2 pounds per million Btu, respectively. At the proposed maximum duct burner firing rate of 466 million Btu per hour, these limits translate to 14 pounds per hour of particulate matter and 93

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[1] Electronic mail communication from Domenic Mignacca (Air Quality Analyst, GVRD) to Bernard Brady (Environmental Engineer, Ecology), June 20, 2000

[2] Apart from approximately bi-weekly, fifteen minute or less system maintenance firings. Such brief oil-firing periods have no measurable impact on regional air quality.

pounds per hour each of SO_2 and NO_x. If the duct burners on both turbines were to be in operation, particulate matter, sulfur dioxide and nitrogen dioxide emissions would increase by 9.4, 3.6, and 6.8 pounds per hour, respectively. Consequently, the permitted emission levels for particulate matter, SO_2 and NO_x are below those required under NSPS.

The following control technologies were considered for NO_x reduction:

- SCONOx
- Selective Catalytic Reduction (SCR)

Because the applicant proposed to use Selective Catalytic Reduction to achieve the same NO_x reduction as would be guaranteed by SCONOx, these control technologies are of equal stringency. The order of their discussion below is arbitrary.

2.2.1.1 SCONOx:

SCONOx is a relatively new NO_x emissions reduction technology. NO_x is reduced by an absorption-reaction mechanism. NO_x is absorbed into a potassium carbonate (K_2CO_3) layer on the catalyst matrix surface. The NO_x reacts with the K_2CO_3 to form potassium nitrate (KNO_3). Eventually, the K_2CO_3 is exhausted. The catalyst-absorbent bed is then taken off-line for regeneration with either natural gas or hydrogen, depending on the system design operating temperature. In the regeneration process, the nitrate is reduced to nitrogen and exhausted up the stack while the KNO_3 is converted back to K_2CO_3. The catalyst-absorbent bed is then cycled back into NO_x reduction service[1].

The SCONOx vendor will guarantee NO_x emissions not to exceed 2 ppmdv when natural gas is burned. SE2 is willing to accept a 2 ppmdv NO_x emission limit (natural gas firing) if they are permitted to install the SCR process. Nonetheless, the SCONOx process still has a potential advantage because it accomplishes NO_x reduction without the use and attendant release of ammonia in the facility’s emissions. Ammonia releases associated with SCR are discussed further in Section 3.2. In addition, SCONOx will reduce emissions of both carbon monoxide (CO) and volatile organic compounds (VOCs) without additional control equipment. This capability for multiple pollutant reduction complicates the BACT analysis process. To account for this, SCONOx will be considered sequentially and incrementally for each pollutant as well as in-toto versus the proposed SCR plus CO-combustion catalysis.

The first commercial-size SCONOx system was installed in May 1995 at the Sunlaw-U.S. Growers 30-megawatt power plant in Vernon, CA. A second SCONOx unit, with improved economic and operational design, was installed in December 1996 at Sunlaw's other 30 megawatt power plant, Federal Cold Storage. The SCONOx pollution control system has been operating satisfactorily in these plants since startup. These are the only two combined-cycle power turbine

[1] Reyes, Boris, SCONOx Catalytic Absorption System, Goal Line Environmental Technologies, 11141 Outlet Dr., Knoxville, TN (December 8, 1998)

facilities operating using SCONOx at this time. In early 1999, Goal Line Environmental Technologies, Inc. announced that it would provide SCONOx systems sufficient to control pollutant emissions from power turbines having up to 300 MW capacity. There is one proposed facility: an air permit has been approved for PG&E to use either SCR or SCONOx to achieve less than 2 parts per million NO_x on a new 510 MW Otay Mesa power plant[1] in San Diego County, CA. If built, this facility would be in an ozone nonattainment area.

The fact that SCONOX has been operating satisfactorily for several years in two facilities demonstrates that the process is technically feasible for relatively small power turbine systems. However, application to SE2 would involve a ten-fold scale up. From an engineering perspective, this is generally considered to be a serious leap in demonstration of technical feasibility. Notwithstanding Goal Lines' faith in SCONOx, it is worthwhile to consider that the proposed PG&E plant would be in an ozone nonattainment area. Proposed commercial facilities that will emit significant amounts of NO_x and/or VOCs in ozone nonattainment areas must install pollution control systems meeting the criteria for the "Lowest Available Emission Rate". These criteria are more stringent than for the same kind of facility proposed to be built in an attainment area. They can direct the control requirement toward technologies that are less thoroughly demonstrated than generally required for BACT. At best, given the level of uncertainty, SCONOx may considered to be marginally technically feasible. Cost data submitted to SE2 by SCONOx vendor (ABB-Alstrom Power, www.abb-alstrom-power.com) indicates that annual costs would be $4,341,803 per turbine or $5,226 per ton of NO_x reduction under fully permitted plant operation.

2.2.1.2 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is an alternative to SCONOx for NO_x emission control. SCR consists of the injection of ammonia into the HRSG exhaust in the presence of oxygen and a platinum, vanadium or titanium catalyst to reduce nitrogen oxides to nitrogen and water. The amount that emissions can be reduced is a function of the catalytic reactor design and the level of ammonia feed. SE2 proposes that using SCR to reduce NO_x emission concentrations to the same degree as SCONOx should be BACT for NO_x. (from 25 ppmdv uncontrolled to 2 ppmdv). Since the same level of control is proposed whether SCONOx or SCR are used, SCR is of equal stringency to SCONOx for the SE2GF BACT analysis.

SCR has been applied successfully for NO_x emission control since at least the late 1980's. Its technical feasibility is above question. Consequently, the choice between SCONOx and SCR rests heavily on cost effectiveness. Cost data submitted by SE2 and modified for consistency with the EPA control cost analysis guidance[2] indicates that annual costs for SCR would be $1,655,776 per turbine or $1,888 per ton of NO_x reduction under fully permitted plant operation[3].

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[1] Two turbine trains.
[2] OAQPS Control Cost Manual (Fourth Edition, 1990, with supplements)
[3] Precise verification of total installation and operating costs for SCR systems is difficult. Most of the installations reported in the OAQPS BACT/LAER Clearinghouse accepted SCR as "top

Although SCR has a significantly lower cost than SCONOx for the same performance, **SCONOx must be considered for its multi-pollutant reduction capabilities before making a final BACT determination.** To do this, the difference between SCR and SCONOx costs for NO_x emission control will be applied to carbon monoxide and VOC control successively, below.

2.2.2 CARBON MONOXIDE CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for CO or VOCs from gas turbines.

Control Options Considered in order of stringency:

- SCONOx (90% carbon monoxide reduction)
- Catalytic Oxidation (80% carbon monoxide reduction)

2.2.2.1 SCONOx

The most stringent means to control carbon monoxide (CO) is SCONOx. As mentioned above, SCONOx reduces CO emissions at the same time as it reduces NO_x. SCONOx reduces CO emissions by catalytically oxidizing the CO to carbon dioxide (CO_2). If SCONOx were to be chosen as the emission control technology, CO emissions should be reduced from 10 ppmdv uncontrolled to 1 ppmdv. This is a 198 ton per year CO reduction per turbine at fully permitted operation. As mentioned above, the SCONOx process is substantially more expensive than the SCR process for NO_x reduction. Due to SCONOx' ability to reduce multiple pollutants, the excess cost can be applied to a CO reduction BACT cost effectiveness determination. The excess in annual cost of SCONOx over SCR for NO_x reduction is $2,686,027. This is $13,566/ton applied as the CO reduction cost.

Recent BACT cost effectiveness analyses for CO reduction for electric power plants indicate CO controls have been imposed up to a cost of about $2,000/ton. This does not represent a firm ceiling to justifiable CO reduction costs. EPA's New Source Review guidance[1] indicates that control technologies that are substantially more expensive than those previously mandated for "similar sources and pollutants" are not justifiable. There are no apparent exacerbating circumstances that raise this standard for SE2GF. Consequently, imposing a CO control cost almost seven times the previous maximum is not justifiable.

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case BACT" in their applications. BACT cost effectiveness estimates are not required in these cases. However, the cost estimate used in this (SE2GF) BACT analysis compares well with the cost estimates for the Satsop Combustion Turbine Project (Elma, WA), Chehalis Generation Facility (Chehalis, WA), Newark Bay Co-generation (Newark, NJ), and Hermiston Generating Co. (Hermiston, OR).

[1] New Source Review Workshop Manual, New Source Review Section, Air Quality Program Branch, USEPA

2.2.2.2 Catalytic Oxidation

The next most stringent means to control CO is catalytic oxidation. The hot HRSG exhaust gas passes through a catalyst section where oxygen in the gas stream is reacted with CO to produce CO_2. This is a well-established technology that is of unquestionable technical feasibility. SE2 proposed using catalytic oxidation to reduce CO emissions from 10 ppmdv uncontrolled to 2 ppmdv. This is a 175 ton per year CO reduction per turbine at fully permitted operation. SE2 estimated the annual cost per turbine to be $418,379, or $2,391/ton CO reduction. Additionally, some VOCs may be destroyed, and a portion of the SO_2 is oxidized to acid mist (SO_3, H_2SO_4) and sulfate compounds. This will be discussed further in sections 2.2.3 and 2.2.5, below.

Although catalytic reduction has a significantly lower cost than SCONOx for CO emission reduction, **SCONOx must still be considered for its ability to remove the additional 1 ppmdv of CO and 90% of the volatile organic compounds (VOCs) before making a final BACT determination.** To do this, the difference between SCR and SCONOx costs for CO emission control to 2 ppmdv will be applied to the additional control, below.

2.2.3 VOLATILE ORGANIC COMPOUND CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for volatile organic compounds (VOCs) from gas turbines.

Control Options Considered in order of stringency:

- SCONOx (90% VOC reduction)
- Catalytic Oxidation (80% VOC reduction)
- Natural gas as the primary fuel and good combustion practice

2.2.3.1 SCONOx

The most stringent means to control volatile organic compounds (VOCs) is SCONOx. As mentioned above, SCONOx reduces VOC emissions at the same time as it reduces NO_x and CO. SCONOx reduces VOC emissions by catalytically oxidizing the VOCs to carbon dioxide (CO_2). If SCONOx were to be chosen as the emission control technology, VOC emissions from each turbine would be reduced from 17.5 lb./hr. uncontrolled to 1.75 lb./hr. This is a 69 ton per year VOC reduction per turbine at fully permitted operation. As mentioned above, the SCONOx process is substantially more expensive than the SCR plus CO-oxidation process for NO_x and CO reduction. Due to SCONOx' ability to reduce multiple pollutants, the excess cost can be applied to a BACT cost effectiveness determination for VOC (and the additional 1 ppmdv or 22 TPY CO) reduction. The excess in annual cost of SCONOx over SCR plus CO-oxidation for NO_x and CO reduction is $2,267,648 per turbine. This is $24,919/ton applied as the VOC and remnant CO reduction cost.

A search of the EPA's BACT/LAER clearinghouse data indicates VOC emission control technology for BACT has not been imposed at costs exceeding about $3,300/ton VOC reduction. This does not represent a firm ceiling to justifiable VOC reduction costs. EPA's New Source Review guidance (*op. cit.*) indicates that control technologies that are substantially more expensive than those previously mandated for "similar sources and pollutants" are not justifiable. There are no apparent exacerbating circumstances that raise this standard for SE2GF. Consequently,, imposing a VOC control cost over eight times the previous maximum is unjustifiable.

2.2.3.2 Catalytic Oxidation

SE2 proposed to install an oxidation catalyst system on each HRSG exhaust. An oxidation catalyst system can reduce both carbon monoxide CO) and volatile organic compounds (VOCs). However, SE2 indicated that these are competing options. Pollutant removal depends on where the catalyst system is placed in the exhaust system. SE2 focused on CO reduction, and made no claim of VOC reduction except for formaldehyde (CH_2O). It is generally accepted that because CH_2O is a simple and partially oxidized organic compound it will oxidize at about the same time and to the same degree as CO[1].

It is technically feasible for SE2 to place an additional catalytic oxidation unit in the exhaust system focusing on VOC reduction. SE2 did not present, propose, or analyze this possibility. However, it is possible to extrapolate a corresponding BACT cost effectiveness estimate from the CO catalytic oxidation analysis.

The cost of an additional unit should be very similar to the CO catalytic oxidation unit because cost is primarily dependent on the volume of exhaust gas, and not the amount of pollutant. Consequently, a reasonable estimate for the additional unit would be about $418,379 per year per turbine. An 80% reduction in VOC emissions would be 55.2 TPY per turbine, yielding a BACT cost effectiveness of $7,579/ton VOC reduction. As mentioned in section 2.2.3.1, a search of the EPA's BACT/LAER clearinghouse data indicates VOC emission control technology has not been imposed at costs exceeding about $3,300/ton VOC reduction. EFSEC'S permit writing contractor believes that imposing a control technology that is twice as costly as the previous maximum is not justifiable. Consequently, **EFSEC's permit writing contractor concludes that a second catalytic oxidation system is not justified for VOC emission reduction.**

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[1] Roy, Sims; Emission Standards Division, Combustion Group, US Environmental Protection Agency Memorandum to Docket A-95-51; *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines*, December 30, 1999 (http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm)

2.2.3.3 Natural gas as the primary fuel and good combustion practice

This is the “no further control” option. The control technology discussion in sections 2.2.3.1 and 2.2.3.2 are based on possible volatile organic compound emission reductions from this level. No feasibility consideration is necessary. There is no BACT cost effectiveness to consider. By default, **EFSEC’s permit writing contractor concludes that natural gas as the primary fuel and good combustion practice is BACT for VOC emission control**.

2.2.4 BACT cost effectiveness considered in terms of total pollutant removal:

The following control technologies were considered in terms of total pollutant reduction:

- SCONOx

As discussed in the previous paragraphs, SCONOx has the capability of reducing NO_x, CO, and VOCs simultaneously. The total expected pollutant reduction would be 1,098 tons per year per turbine. The annual operating cost per turbine is expected to be $4,341,803. So, the BACT cost effectiveness is $3,954 per ton total pollutant removal. Analysis of the data in EPA’s BACT/LAER clearinghouse indicate that for multiple pollutant removal systems, the maximum combined BACT cost effectiveness is around $2,500 per ton. Considering the marginal technical feasibility of the SCONOx process, EFSEC's permit writing contractor concludes that the disparity between historical, combined pollutant BACT cost effectiveness and the BACT cost for SCONOx is unreasonably high. **EFSEC’s permit writing contractor concludes that considering total pollutant removal capability does not justify the SCONOx process for application to SE2.**

2.2.5 BACT Determination for NO_x, CO, and VOCs:

The above analysis demonstrates that at this time the SCONOx process is marginally technically feasible as an emission control technology for power turbines, and is unjustifiably expensive whether considered for its multi-pollutant reduction capability from a sequential or total perspective.

EFSEC’s permit writing contractor agrees with SE2’s evaluation and determines BACT for NO_x to be selective catalytic reduction. The draft PSD permit limits NO_x emissions to a three hour average concentration 2 ppmdv, corrected to 15.0 percent oxygen except during startup and shutdown. The applicability of permit limits applicable to startup and shutdown are discussed under § 2.2.9, below. NO_X emissions from each exhaust stack shall be measured and recorded by a continuous emission monitoring system that meets the requirements of 40 CFR 60, Appendix F.

EFSEC’s permit writing contractor agrees with SE2’s evaluation and determines BACT for CO to be catalytic oxidation. The draft PSD permit limits CO emissions to a one hour average concentration 2 ppmdv, corrected to 15.0 percent oxygen except during startup and shutdown. The applicability of permit limits applicable to startup and shutdown are discussed under § 2.2.9, below. Each stack will be equipped with continuous CO monitoring that meets the requirements of 40 CFR 60, Appendix F.

EFSEC's permit writing contractor agrees with SE2's evaluation and determines BACT for VOC to be use of natural gas as the fuel and good combustion practice. The draft PSD permit limits volatile organic compound (VOC) emissions from each HRSG exhaust stack to 3.5 pounds per hour when firing natural gas under base load without duct firing, or 17.5 pounds per hour under base load with duct firing.

2.2.6 SULFUR DIOXIDE CONTROL

Federal new source performance standards (40 CFR 60.330 Subpart GG) for turbines limit sulfur dioxide (SO_2) emissions to 150 ppmdv at 15 percent O_2 and by limiting sulfur content of the natural gas to 0.8 percent by weight.

SE2 proposes and **EFSEC's permit writing contractor agrees with SE2GF that using only pipeline quality natural gas as fuel constitutes BACT for SO_2 control.** SE2 would be using natural gas containing low sulfur levels (approximately 1.1 grains per 100 cubic foot of natural gas). The draft PSD permit limits the SO_2 emission level to one ppmdv. The draft PSD permit requires that the sulfur content of the fuel be monitored in accordance with 40 CFR 60.334(b), and in accordance with 40 CFR 75 Appendix D.

2.2.7 SULFUR TRIOXIDE AND SULFURIC ACID CONTROL

SE2 estimates that 13.5% of the SO_2 will oxidize to sulfur trioxide (SO_3) as a combined result of turbine combustion equilibria and the post-oxidation catalytic system (CO control)[1]. SE2 proposes and **EFSEC's permit writing contractor agrees with SE2GF that using only natural gas as fuel constitutes BACT for SO_3 control.** Virtually all the SO_3 should hydrolyze by reaction with water vapor in the exhaust gas to sulfuric acid. The permitted sulfuric acid emission level from each HRSG stack is 39 pounds per day. Because SE2GF will use ammonia injection to control NO_x, most if not all of the sulfuric acid will be neutralized to ammonium sulfate and bisulfate in the condensing exhaust plume.

2.2.8 PARTICULATE AND PM_{10} CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for particulate or for particulate matter less than 10 microns (PM_{10}) emitted from gas turbines.

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[1] Data supplied to SE2GF by Nooter-Erickson, the vendor of the heat recover steam generator and CO-combustion catalytic systems.

SE2 proposes and **EFSEC's permit writing contractor agrees with SE2GF that good combustion practice, using only natural gas as fuel constitutes BACT for PM_{10} emissions**. The draft PSD permit limits total PM_{10} emissions to 573 pounds per day per stack as demonstrated under maximum load conditions.

2.2.9 EMISSION LIMITS FOR STARTUP AND SHUTDOWN CONDITIONS

During startup and shutdown, either or both the SCR or CO combustion catalyst systems may not be in the normal operating temperature range. In the respective case, NO_x and/or CO emissions concentrations cannot be controlled below the emission limits specified in the draft PSD permit for normal operation. However, if any combustion is occurring through a turbine, the hot exhaust gasses are passing through the catalyst beds. The catalyst beds would heat up very rapidly during startup, and would cool down very slowly during shutdown. Consequently, the period of uncontrolled NO_x and/or CO emissions would be relatively short, and unlikely to encompass the full period of startup or shutdown.

Sulfur oxide and particulate mass emissions are directly related to fuel consumption. They are not significantly affected by the operation of the SCR or CO combustion catalyst system. They decrease in direct proportion to fuel consumed in the combustion turbines and duct burners. VOC emissions appear to increase relative to fuel consumption during startup or shutdown due to inferior combustion dynamics during these periods. However, 75% of the modeled VOC emissions are attributable to operation of the duct burners. Operation of the duct burners during startup or shutdown is very unlikely. Consequently, even under the inferior combustion conditions of startup or shutdown, VOC emissions would be below modeled levels[1].

Nonetheless, EPA guidance[2] indicates that if the emission limits specified for normal operation are not feasible under startup or shutdown, PSD permits must specify startup and shutdown emission limits that are protective of the NAAQS. The proposed permit has specified such conditions:

- NO_x is a NAAQS based on an annual average. The annual limit is retained under startup and shutdown. The sum of all NO_x emissions from the facility, including emissions during startup and shutdown, would not exceed the annual limit established in the permit.
- The BACT-based short-term limit for CO under normal operation is one five-thousandth of the NAAQS. The increased allowable CO emission concentration during startup and shutdown retains a large protective margin. It is below the U.S. significant impact level (SIL), less than 5% of the NAAQS, and about 12% of the Canadian air quality standard for CO.
- As stated above, sulfur oxide and particulate mass emissions decrease with fuel consumption. Conditions related to startup and shutdown operation do not threaten NAAQS protection

[1] In any event, at no time would SE2GF be relieved of the daily limit on VOC emissions.
[2] Rasnic, John, Director Stationary Source Division, Office of Air Quality Planning and Standards to Linda Murphy, director, Air, Pesticides and Toxics Management Division, Region 1; "Automatic or Blanket Exemptions for Excess Emissions During Startup and Shutdowns Under PSD (January 28, 1993)

relative to these pollutants. For purposes of compliance reporting, sulfur oxide and PM_{10} emissions are determined from fuel use. The sum of all sulfur oxide and particulate matter emissions from the facility, including emissions during startup and shutdown, would not exceed the daily limits established in the permit.

- A parametric equation relating fuel use to VOC emissions was determined from the vendor's operating data. The permit requires the facility to calculate VOC emissions during startup and shutdown for comparison to the specified mass emission limit. The sum of all VOC emissions from the facility, including emissions during startup and shutdown, would not exceed the daily limits established in the permit.

3. AMBIENT AIR QUALITY ANALYSIS

3.1 REGULATED POLLUTANTS

PSD rules require an ambient air quality impacts assessment (40 CFR Part 52.21) from any facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to maximum allowable increments prevents significant deterioration of air quality.

SE2 submitted a preliminary modeling analysis to EFSEC proposing the modeling approach. EFSEC's permit writing contractor agreed with the analysis and determined that pre-construction monitoring would not be required. The 1985-89 surface observations at Abbotsford Airport[1] provided the necessary meteorological data for the modeling exercise. Monitoring data from Abbotsford for 1996-99 provided the estimates for background criteria pollutant concentrations[2]. SE2 applied this data along with the anticipated pollutant emissions in a sophisticated and generally accepted model to determine the air quality impact of the proposed facility[3].

Ambient impact analysis indicates that all regulated pollutants are well below ambient air quality standards established to protect human health and welfare.

3.2 TOXIC AIR POLLUTANTS

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". The TAPs are evaluated for both acute (24 hour) and chronic (annual) effects. The quantities of all TAPs that would be emitted from the turbines and duct burner were estimated and modeled to determine their maximum ambient concentrations. These maximum ambient concentrations

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[1] These data are collected by the Canadian Climate Service using instruments and methods similar to the National Weather Service at United States airports.

[2] Collected by the Greater Regional Vancouver District

[3] CALPUFF modeling system, Phase 2 Summary Report and Recommendations for Modeling Long Range Transport and Impacts, EPA-454/R-98-019, Interagency Workgroup on Air Quality Modeling, USEPA Office of Air Quality Planning and Standards, Research Triangle Park, NC27711 (1998)

were compared to the respective acceptable source impact levels (ASIL). These ASILs are not health effect levels, but thresholds that, if exceeded, indicate the need for further investigation.

SE2GF would emit small quantities of organic TAPs as products of incomplete combustion. As discussed in Section 2.2, EFSEC's permit writing contractor determined that BACT for the criteria pollutants for SE2GF is SCR, CO-catalytic combustion, good combustion practice, and use of pipeline quality natural gas as fuel. Under this control system, operating at full design rate, ambient concentrations of all of the TAPs were found to be well below the ASILs. On the average, anticipated TAP emissions are less than 10% of the ASILs.

Ammonia emissions from SE2GF deserve special discussion. Ammonia is a TAP defined in WAC 173-460[1]. Ammonia is released from the SCR process because a slight excess is required to force NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip." Sumas proposed a permit limit of 5 ppmdv on the emissions of unreacted ammonia. At 5 ppmdv, the maximum modeled ammonia concentration outside the boundary of SE2GF is about 3 % of the ASIL; i.e., well below concern. This concentration is also one-third of the odor threshold, about one percent of the lower limit for skin and throat irritation, and about one five hundredth the fatal acute toxicity level. Consequently, **EFSEC's permit writing contractor concludes that a 5 ppmdv ammonia emission limit for SE2GF does not threaten human health.** Nonetheless, there is one more consideration relative to ammonia as a TAP.

Prior to the commercialization of the SCONOx process, SCR was unquestionably BACT. As discussed in Section 2, SCONOx has not passed the economic test of BACT cost effectiveness for criteria pollutant control for SE2GF. However, because the use of SCONOx would eliminate ammonia emissions, Chapter 173-460 WAC requires that SCONOx be considered as a possibility for BACT for TAPs (T-BACT). By substituting a reasonable BACT cost effectiveness for VOC reduction for the calculation outlined in Section 2.2.3.1, the excess SCONOx cost can be applied to evaluate the cost effectiveness for ammonia reduction. For the purpose of this exercise, we impose a $4,000 per ton ceiling for the VOC and extra CO reduction. This leaves an annual cost per turbine of $1,899,648 for SCONOx that can be applied as an ammonia reduction cost. For the 69.6 ton per year ammonia reduction per turbine, this is $27,294/ton. Since there is no apparent health risk from the ammonia emissions, this is not a justifiable control cost. Consequently, **EFSEC's permit writing contractor agrees with SE2's evaluation and determines T-BACT for ammonia emissions is SCR with an emission limit of 5 ppmdv.**

Ammonia is a Washington State toxic air pollutant (TAP) by itself, and also combines with hydrated sulfur and nitrogen oxides to form the corresponding salts. Environmentally these salts are particulates that contribute to visible haze. Inevitably, these salts deposit in soils, and may

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[1] Ammonia is also a hazardous material to transport and store on site. However, SE2GF would be using an aqueous solution that is 19% ammonia by weight. This is much less hazardous than liquefied ammonia gas, albeit more expensive. On-site aqueous ammonia storage will be surrounded by a containment berm to prevent escape in the event of a leak.

cause excessive nitrogenous enrichment. This is discussed further below in Section 4.1.2.

4. AIR QUALITY RELATED VALUES

The PSD regulations require an evaluation of the effects of the anticipated emissions on visibility, soils, and vegetation in Class I and II areas and the effect of increased air pollutant concentrations on flora and fauna in the Class I areas specific to the proposed source. Impacts were evaluated for the five established and one proposed Class I areas within 175 km[1]. At the recommendation of the federal land managers, SE2 used CALPUFF (*op. cit.*) to analyze the possible impacts on visibility and deposition discussed below.

4.1 Visibility

The federal land managers suggested a 5% reduction in visibility as the significance threshold. The regional haze impact assessment indicated visibility impacts on Class I areas attributable to SE2GF's operation are less than this significance level under all modeled meteorological conditions. **EFSEC's permit writing contractor concludes that SE2GF is unlikely to have a significant impact on visibility in Class I areas.**

Due to its proximity to the U.S.-Canada international border, SE2GF may have visibility effects on Canadian areas with analogous standing to U.S. Class I areas. Canada has not specifically designated such areas. However, Pacific Rim, Mount Revelstoke, Glacier, Yoho, and Kootenay are Canadian national parks located in British Columbia relatively near the international border. For the purpose of considering SE2GF's visibility impact on sensitive Canadian areas, these may be considered surrogates for U.S. Class I areas. All but Pacific Rim National Park are located well-East of Sumas, near the projection of the Washington-Idaho border. The dispersion modeling results indicate visibility impacts from SE2GF on these national parks to the east will be very low. Pacific Rim National Park is about half-again farther from SE2GF than is Olympic National Park. The dispersion modeling results indicate the visibility impact from SE2GF on Pacific Rim National Park will be less than half the impact on Olympic National Park, i.e. less than a 5% visibility reduction. **EFSEC's permit writing contractor concludes that SE2GF is unlikely to have a significant impact on visibility in national parks in British Columbia.**

British Columbia's Ministry of Environment requested that SE2 estimate visibility impacts on lines-of-sight surrounding Abbotsford, B.C. Abbotsford is analogous to a Class II area in the U.S. The following conclusions are based on the data provided by SE2 in response to that request[2].

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[1] Olympic National Park, Alpine Lakes Wilderness, Glacier Peaks Wilderness, North Cascades National Park, and Pasayten Wilderness are the relevant Class I areas. The Mt. Baker Wilderness, although not an official Class I area, was included and treated as a Class I area in the SE2 application.

[2] Eaden, David N. (Vice President Engineering and Construction, Sumas Energy 2, Inc.) to Wallis, Hu (Manager, Air Quality Assessment, Ministry of Environment, Lands and Parks, Victoria, B.C.), "MFG Responses to MELP Comments of February 23, 2000", April 18 2000,

Regardless of the season, there is less than a ten percent chance that SE2GF will contribute significantly to perceptible visibility reduction[1] along lines-of-sight from Abbotsford. The remaining Class II areas are further from SE2GF than the Lower Fraser Valley. Visibility impacts on them should be even lower than may be experienced relative to Abbotsford. **EFSEC's permit writing contractor concludes that SE2GF is unlikely to have a significant impact on visibility in the surrounding Class II areas.**

4.2 Air Quality and Deposition Impact

Air concentrations of ozone, nitrogen oxides, and sulfur oxides and fallout from derivatives have the potential to impact flora and fauna in the area surrounding an emissions source. SE2 modeled the maximum increases in air concentrations of the acid precursor pollutants, NO_x and SO_2, caused by SE2GF. They do not exceed 0.03% of the US Forest Service (USFS) criteria for sensitive specie protection. Ozone is a derivative of complex reactions of VOCs and NO_x from SE2GF and all other sources including natural ones. Because of this complexity, reliable models for predicting ozone concentrations caused by SE2GF are not available. However, VOC emissions from SE2GF are about the same as the NO_x emissions. It is reasonable to conclude that the ultimate ozone impact attributable to SE2GF relative to all other emissions sources would be similar to the NO_x impact, i.e., very low.

According to the EPA's New Source Review guidance (*op. cit.*), for most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards will not result in harmful effects. Ambient criteria pollutant concentrations attributable to SE2GF are expected to be a small fraction of the secondary national ambient air quality standards. Modeled annual surface deposition rates of nitrogen and sulfur would not exceed 0.1% of the USFS/National Park Service criteria for soil and aquatic protection. Maximum ozone, nitrogen oxides, and sulfur oxides concentration increases and surface deposition caused by SE2GF in British Columbia's national parks should be even lower than estimated for the U.S. Class I areas. Surface deposition of nitrogenous compounds from SE2GF in the British Columbia's Lower Fraser Valley should be about 1% of the total from all sources[2],

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pages 38-52

[1] As in the discussion, above, concerning Class I areas, "perceptible" is defined as a 5% or greater visibility reduction.

[2] Belzer, Wayne, Ammonia, Nitrate, and Sulfate: Concentrations in Air and Rainfall and Their Contribution to Fine Particulate Formation in the Lower Fraser Valley of

and about 2 % of the US Forest Service threshold for potential injury to plants and forest ecosystems. The average sulfur compound deposition rate attributable to SE2GF in the Lower Fraser Valley should be about 9% of the total from all sources (*op. cit.*) and 5% of the US Forest Service threshold for likely effects on terrestrial ecosystems. Current deposition rates of sulfur compounds in the Lower Fraser Valley are about one-half the US Forest Service threshold for likely effects on terrestrial ecosystems. **EFSEC's permit writing contractor concludes that SE2GF is unlikely to have a significant impact on vegetation, soils, and aquatic resources in Class I or Class II areas or the analogous areas in British Columbia.**

4.3 OTHER AIR QUALITY IMPACTS

During the construction phase of the project construction workers will be employed, requiring temporary housing and producing motor vehicle emissions during their daily commute to the work site and from the operation of heavy and other internal combustion engine powered equipment at the project site. During construction, there is the possibility of generating wind blown dust from earth moving operations and vehicle and equipment operation of unpaved areas of the project site or access roads. This dust is not subject to PSD or New Source permitting, but can be restricted during the SEPA process.

It is expected that the majority of employees would come from the local area.

5. AIR POLLUTION CONTROL REGULATORY REQUIREMENTS

This project is subject to the following federal regulations:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards	40 CFR 60, Subpart Da
New Source Performance Standards	40 CFR 60, Subpart GG
New Source Performance Standards, Quality Assurance Procedures	40 CFR 60, Appendix F
New Source Performance Standards, Performance Specifications	40 CFR 60, Appendix B

Permitting:

Emissions Monitoring and Permitting	40 CFR 75
Monitoring sulfur content of natural gas to be monitored	CFR 60.334(b)(2)
NO_x Requirements	40 CFR 76

British Columbia, Presented at the Air and Waste Management Assoc. 91st Ann. Meeting (June 14-18, 1998)

The source is subject to the following state regulations:

General and Operating Permit Regulations for Air Polluting Sources	463-39 WAC
General Regulations for Air Pollution Sources	173-400 WAC
Operating Permit Regulation	173-401 WAC
Controls For New Sources of Toxic Air Pollutants	173-460 WAC