Appendix A-1

BACT Analysis

APPENDIX A-1
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

In Washington, Best Available Control Technology BACT is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. This Appendix presents a BACT analysis for emission units associated with the Grays Harbor Energy project. The basis for the emissions-related analyses is annual average operation at a nominal design capacity of 530 gross megawatts (MW).

A-1.1 BACT ANALYSIS OVERVIEW AND RESULTS SUMMARY

The proposed BACT controls and associated emission rates for each proposed emission unit are summarized in Table A-1-1. Project sources addressed in this table include:

- Two combined-cycle natural gas-fired combustion turbines;
- Two 5-cell, recirculating, mechanical-draft cooling towers for the combined cycle plants;
- One auxiliary boiler; and
- Two diesel-fueled engines for emergency electricity generation and fire water.

Figure 2.3-1 in Section 2.3 (Construction on Site) of this Application provides an illustration of the proposed project indicating the layout of the major plant components within the site.

TABLE A-1-1
PROPOSED BACT FOR GRAYS HARBOR ENERGY CENTER

Pollutant	Control	Emissions Limits
Combustion Turbines (per combustion turbine excluding start up & shutdown).		
NO_x	Selective Catalytic Reduction (SCR)	2 ppmvd @ 15% O_2, 3-hour average
CO	Oxidation Catalyst	2 ppmvd @ 15% O_2 (above 60% load), 3-hour average
PM/PM_{10}	Good Combustion Practices (GCP), Gaseous Fuels only	0.007 lb/MMBtu, 24-hour average
SO_2	Pipeline Natural Gas	None
VOC	GCP	1 ppmvd @ 15% O_2 100% load 3 ppmvd @ 15% O2 60% load
NH_3	Molar ratio control on Injection System	5 ppmvd @ 15% O_2, 20 lb/hr (BACT-based Limit)
H_2SO_4	Pipeline Natural Gas	None
TAPs	GCP, Pipeline Natural Gas	None
Auxiliary Boiler (Natural Gas-Fired, <30 MMBtu/hr heat input)		
NO_x	GCP, Ultra-Low-NO_x burner	0.011 lb/MMBtu @ 3% O_2, approx 9 ppmvd, 3-hr average
CO	GCP	0.037 lb/MMBtu @ 3% O_2, approx 50 ppmvd, 3-hr average
PM/PM_{10}	GCP, Gaseous Fuels Only	None
SO_2	Pipeline Natural Gas	None
VOC	GCP	None
TAPs	GCP, Pipeline Natural Gas	None
Cooling Towers (10ell, Mechanical Draft Type)		
PM/PM_{10}	High Efficiency Mist Eliminators, TDS limit in circulating water	0.0005% draft as percent of circulating water
Diesel Engines		
NO_x	Combustion controls, restricted operating hours	40 CFR Part60, Subpart IIII emission standards for emergency stationary compression ignition internal combustion engines; Operation of each engine limited to ≤ 26hours/year of non-emergency operation; Use of ultra-low-sulfur (15 parts per million of sulfur by weight) diesel fuel.
CO	Combustion controls, restricted operating hours	
PM/PM_{10}	Combustion controls, restricted operating hours, ultra-low-sulfur fuel	
SO_2	Ultra-low-sulfur diesel fuel, restricted operating hours	
VOC	Combustion controls, restricted operating hours	
TAPs	Combustion controls, restricted operating hours, ultra-low-sulfur fuel	

The following sections describe the BACT demonstration process, and the individual control technology evaluations for each emission unit and pollutant subject to BACT-based limits.

A-1.2 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation 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 ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990)[1]:

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

Step 2. Eliminate all technically infeasible control technologies;

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

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

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

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a

[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

“top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams’ physical and chemical characteristics.

A-1.3 COMBUSTION TURBINE BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the combustion turbines proposed for Units 3 and 4 to determine appropriate BACT emission limits. This BACT analysis is based on the current state of emissions control technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

A-1.3.1 PROCESS DESCRIPTION

The project will add two natural gas-fired combined cycle (NGCC) combustion turbines. Each combustion turbine will be paired with a HRSG with duct burners. Steam from the two HRSGs will be sent to a single steam turbine that will turn a power generator. Both the combustion turbines as well as the duct burners will be fueled only by pipeline quality natural gas. Pollutant emissions from the NGCC combustion turbine units will include NO_x, PM_{10}, $PM_{2.5}$, CO, SO_2, and VOCs.

A-1.3.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. Table A-1-2 lists a number of recent BACT determinations in recent years for NGCC combustion turbine projects.

TABLE A-1-2
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED COMBINED-CYCLE COMBUSTION TURBINES

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
FL-0304	09-08-08	Florida Municipal Power Agency	Osceola County, FL	Combined Cycle Gas Turbine	1,860 MMBtu/hr	NO_X – 2 ppmvd CO – 6 ppmvd 10% Opacity	SCR, GCPs, Low Sulfur Fuel	BACT-PSD
FL-0303	07-30-08	Florida Power & Light Co.	Palm Beach County, FL	Combined Cycle Gas Turbines (3)	2,333 MMBtu/hr (each unit)	NO_X – 2 ppmvd CO – 6 ppmvd VOC – 1.2 ppmvd 10% Opacity	LNBs, SCR, GCPs, Low Sulfur Fuel,	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Company (SWEPCO)	Caddo County, LA	Combined Cycle Gas Turbine	2,110 MMBtu/hr	NO_X – 4 ppmvd@15% O_2 CO – 10 ppmvd @ 15%O_2 VOC – 4.9 ppmvd @ 15%O_2 PM_{10} – 0.011 lb/MMBtu SO_2 – 0.0057 lb/MMBtu	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD
CT-0151	02-25-08	Kleen Energy Systems, LLC	Middlesex County, CT	Combustion Turbine with Duct Burner	2.1 MMcf/hr	NO_X – 2 ppm @ 15% O_2 CO – 0.9 ppmvd @ 15%O_2 VOC – 5 ppmvd @ 15%O_2 PM_{10} – 0.006 lb/MMBtu SO_2 – 0.0020 lb/MMBtu	LNBs, SCR, Oxidation Catalyst	LAER (NO_X); BACT-PSD
VA-0308	01-14-08	CPV Warren	Warren County, VA	Combined Cycle Gas Turbine with Duct Burner	1,717-2,204 MMBtu/hr	NO_X – 2 ppmvd CO – 1.2 ppmvd VOC – 0.7 ppmvd PM_{10} – 0.013 lb/MMBtu SO_2 – 0.002 lb/MMBtu	LNBs, SCR, GCPs, Oxidation Catalyst	BACT-PSD
GA-0127	01-07-08	Southern Company/ Georgia Power	Cobb County, GA	Combined Cycle Combustion Turbine	254 MW	NO_X – 6 ppmvd @ 15% O_2 CO – 1.8 ppmvd @ 15%O_2 VOC – 1.8 ppmvd @ 15%O_2 PM_{10} – 0.1 lb/MMBtu 20% Opacity	LNBs, SCR, Water Injection, Oxidation Catalyst	LAER (VOC); PSD-BACT

TABLE A-1-2 (Continued)
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED COMBINED-CYCLE COMBUSTION TURBINES

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0071	06-05-07	Minnesota Municipal Power Agency	Rice County, MN	Combined Cycle Combustion Turbine with Duct Burner	1,758 MMBtu/hr	NO_X – 3 ppmvd CO – 9 ppmvd VOC – 3 ppmvd PM_{10} – 0.01 lb/MMBtu	LNBs, SCR, Water Injection, GCPs	BACT-PSD
CA-1144	04-25-07	Caithness Blythe II, LLC	Riverside County, CA	Combined Cycle Combustion Turbine	170 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 4 ppmvd @ 15%O_2	SCR	BACT-PSD
FL-0285	01-26-07	Progress Energy Florida (PEF)	Pinellas County, FL	Combined Cycle Combustion Turbine	1,972 MMBtu/hr	NO_X – 15 ppmvd CO – 8 ppmvd VOC – 1.5 ppmvd @ 15%O_2 10% Opacity	Water Injection, GCPs	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	West Palm Beach County, FL	Combined Cycle Combustion Gas Turbine	2,333 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 8 ppmvd @ 15%O_2 VOC – 1.5 ppmvd @ 15%O_2	LNBs, SCR, Water Injection	BACT-PSD
OK-0115	12-12-06	Energetix	Comanche County, OK	Combustion Turbine And Duct Burner	1,911 MMBtu/hr	NO_X – 3.5 ppmvd @ 15% O_2 CO – 16.4 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu	LNBs, SCR, GCPs	BACT-PSD
NY-0095	05-10-06	Caithness Bellport, LLC	Suffolk County, NY	Combined Cycle Combustion Turbine	2,221 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu SO_2 – 0.0011 lb/MMBtu	SCR, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD
CO-0056	05-02-06	Calpine Corp.	Weld County, CO	Combined Cycle Turbine	300 MW	NO_X – 3 ppm @ 15% O_2 CO – 3 ppm @ 15%O_2 VOC – 0.0029 lb/MMBtu PM_{10} – 0.0074 lb/MMBtu 10% Opacity	LNBs, SCR, GCPs, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD
NC-0101	09-29-05	Forsyth Energy Projects, LLC	Forsyth County, NC	Combined Cycle Turbine	1,844 MMBtu/hr	NO_X – 3 ppm @ 15% O_2 CO – 11.6 ppm @ 15%O_2 VOC – 5.7 ppm @ 15%O_2 PM_{10} – 0.019 lb/MMBtu SO_2 – 0.0006 lb/MMBtu	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD
NV-0035	08-16-05	Sierra Pacific Power Company	Storey County County, NV	Combined Cycle Combustion Turbine with Duct Burner.	306 MW	NO_X – 2 ppm @ 15% O_2 CO – 3.5 ppm @ 15%O_2 VOC – 4 ppm @ 15%O_2 PM_{10} – 0.011 lb/MMBtu	SCR, Oxidation Catalyst, GCPs	BACT-PSD

The RBLC database survey results indicate that available BACT options for the pollutants emitted from NGCC combustion turbines include:

- Low NO_x Burners (LNBs)
- XONON
- Selective Catalytic Reduction (SCR)
- EMx (formerly SCONOx)
- Selective Non-Catalytic Reduction (SNCR)
- Good Combustion Practices (GCPs)
- Oxidation Catalysts
- Low sulfur fuels
- Flue Gas Desulfurization (FGD)

A-1.3.3 OXIDES OF NITROGEN BACT

NO_x is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the NGCC combustion turbines will originate as thermal NO_x.

The combustion turbines proposed for the project can achieve a nominal NO_x emission rate of 0.06 lb/MMBtu without post-combustion controls (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbines.

The rate of formation of thermal NO_x in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent injection (e.g., steam) and dry low-NO_x burners. Post-combustion controls (e.g., SCR) seek to convert NO_x formed during combustion to nitrogen and water using a reductant injected into the exhaust. These technologies are considered to be commercially available pollution prevention techniques.

A-1.3.3.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previously issued permits and through RBLC queries for facilities that include NGCC combustion turbines. Table A-1-2 summarizes the NO_X control technologies and permit limits for NGCC combustion turbines similar to those proposed for this project. For this top-down analysis, all of the following technologies were considered to be potentially available for the Units 3 and 4 combustion turbines:

Combustion Process Controls

- LNBs
- XONON

Post-Combustion Controls

- SCR
- EMx (formerly SCONOx)
- SNCR

A-1.3.3.2 Evaluate Technical Feasibility

Each identified technology is first examined to determine if it is technically feasible to control NO_x emissions from natural gas-fired combustion turbines. First, controls potentially achieved by modifications to the combustion process itself are considered. Next, potential control methods utilizing add-on control equipment, such as SCR, to remove NO_x from the exhaust gas stream after its formation during combustion are examined.

Dry Low NO_x Burners

Low-NO_x Burners (LNBs) burners control NO_x formation in NGCC combustion turbines by staged combustion of the natural gas. This is done by designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. LNBs are a technically feasible control option for this unit, and, at this point, are considered a baseline level of control for all NGCC combustion turbine projects.

XONON

XONON is a technology developed by Catalytica Combustion Systems to lower the temperatures in conventional combustion turbine combustors, and, therefore, reduce NO_x formation. However, XONON has been demonstrated only on smaller combustion turbiness (i.e., 1.5 MW), and has not yet been scaled up for use on larger combustion turbines such as the GE 7FA or Siemens STG6-5000F. As a result, XONON is not considered technically feasible for use on the proposed NGCC combustion turbine units, and is eliminated from further consideration as BACT.

SCR

SCR is a technology that achieves post-combustion reduction of NO_x from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_x to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), a structured, fixed-bed catalyst module, and electronic controls. SCR is a common control technology for use on NGCC combustion turbines.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In a natural gas-fired turbine, NO_x removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Compounds such as sulfur and certain metals, if present in the exhaust gas stream, can “poison” the catalyst, impacting catalyst activity, inhibiting conversion efficiency, and reducing the useful life of the catalyst.

EMx

The EMx (formerly SCONOx) system is an add-on control device that reduces emissions of multiple pollutants. EMx control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). EMx utilizes a single catalyst for the reduction of CO, VOC and NO_x, which are converted to CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several EMx units in commercial installations worldwide, although all are applied to emission units that are much smaller than those proposed for the project. The original application of EMx was at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation was on a GE LM2500, an approximately 34 MW combined cycle system, which has had an operating EMx system since December 1996. That system has undergone many changes over the years. The second commissioning of a EMx system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm, and subsequently received a permit modification extending the EMx demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of EMx on large combustion turbine units such as those proposed for this project. EMx was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large NGCC power stations, additional concerns include the following:

- EMx uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed NGCC units are significantly larger than the much smaller facilities where EMx has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the proposed combustion turbines.
- The EMx catalyst is very susceptible to poisoning by sulfur compounds. Because pipeline natural gas contains some sulfur, a separate catalyst system or filter may be required to absorb SO_2 before it could contact the catalyst bed. However, operation of such an SO_2 absorbtion system on a combustion turbine is not proven, and, upon regeneration, the process would create an H_2S stream requiring treatment.
- EMx would not be expected to achieve lower guaranteed NO_x levels than SCR, and, for reasons described above, it has greater feasibility concerns than SCR for application on large NGCC combustion turbines.

Although application of an EMx system to a large-scale NGCC combustion turbine has not be demonstrated in practice, it must be considered technically feasible for such an application. However, the high capital and operating costs of the EMx system make it not cost effective when compared to an SCR system capable of achieving similar emission rates. This cost-effectivenss determination was proposed for both the Cherry Point Cogeneration Project Electric Generating Facility and the Sumas Energy 2 Generation Facility and accepted by the Washington Energy Site Evaluation Council (EFSEC). Because the economics associated with applying an EMx system to the combustion turbines proposed for the project are substantially the same as those presented for the Cherry Point and Sumas Energy 2 projects, the cost-effectiveness analysis in not repeated here.

SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (anhydrous NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 discharge from the stack (known as "ammonia slip") will be very high.

This technology is occasionally used in heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been used in CT applications to control NO_x, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible and is removed from further consideration as BACT.

A-1.3.3.3 Rank Control Technologies

Among the control technologies considered in the previous subsection, only the use of low-NO_x combustors and installation of an SCR system were considered both technically feasible and cost-effective to reduce NO_x emissions from the NGCC combustion turbines, and LNBs are considered the baseline NO_x control technology.

A-1.3.3.4 Evaluate Control Options

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is an SCR system. The most notable environmental impact associated with this NO_x control technology is NH_3 emissions associated with use of NH_3 as the reagent chemical. The unreacted portion of the NH_3 passes through the catalyst and is emitted from the stack. These emissions are referred to as "ammonia slip," and their magnitude depends on the catalyst activity and the degree of NO_x control desired.

Economic and energy impacts associated with application of an SCR system are a decrease in the net power output of the units due to the increased pressue drop across the catalyst bed, the ongoing ammonia procurement and storage requirements, and increased maintenance costs associated with the accumulation of ammonia salts on the HRSG and the eventual de-activation of the catalyst. Because SCR has long been considered BACT for large NGCC combustion turbine units, the environmental, economic, and energy impacts have generally been deemed acceptable by USEPA and Ecology.

A-1.3.3.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. Grays Harbor Energy proposes that the use of LNBs and installation of an SCR system to reduce NO_x exhaust gas concentration to 2 ppmv NO_x at 15% O_2 (3-hour average) be considered BACT for the combustion turbines.

A-1.3.4 CARBON MONOXIDE BACT

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

A-1.3.4.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the proposed NGCC combustion turbines for control of CO emissions:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post-Combustion Controls

- EMx (formerly SCONOx)
- Oxidation Catalyst

A-1.3.4.2 Evaluate Technical Feasibility

Each identified technology was evaluated in terms of its technical feasibility for application to NGCC combustion turbines.

Good Combustion Practices

GCPs include operational and combustor design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. Such control practices applied to the proposed NGCC combustion turbines can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower loads (50-70 percent), the combustion efficiency drops off notably, and CO emissions would be higher. GCPs are a technically feasible method of controlling CO emissions from the proposed NGCC combustion turbines, and are considered the baseline control technology.

EMx

The EMx system was described in the BACT analysis for control of NO_x emissions from NGCC combustion turbines. It is commercially available for small combustion turbines for controlling CO and can reduce emissions by up to 95 percent. As discussed in the NO_x BACT discussion however, it is not commercially available for large combustion turbines (like those proposed for this project). Furthermore, several recent BACT analyses for combustion turbine projects have determined that EMx is not a cost effective control technology, despite its alleged ability to control multiple pollutants.

Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The catalyst oxidizes CO to CO_2, and VOCs to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_x and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

Oxidation catalyst systems typically operate at temperatures between 750 to 1,100ºF (400 to 600ºC), and increased operating temperatures within that range generally result in more effective oxidation reactions. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90 percent, and typical VOC conversion efficiencies are 40 to 50 percent.[2] This technology has been required CO control equipment in a significant number of permits for NGCC combustion turbine projects, and is considered technically feasible for application to an NGCC combustion tubine.

A-1.3.4.3 Rank Control Technologies

GCPs and oxidation catalysts were found to be technically feasible for the proposed NGCC combustion turbines. GCPs are the baseline control technology, and oxidation catalyst systems are considered to be more effective. In practice, GCPs are always used, and an oxidation catalyst system would be used in addition to, not in place of, GCPs.

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

A-1.3.4.4 Select Control Technologies

The use of GCPs in conjunction with an oxidation catalyst system is proposed to be BACT for control of CO from NGCC combustion turbines. Grays Harbor Energy proposes that the CO BACT-based limit should be 2 ppmvd at 15 percent O_2 on a 3-hour average during non-startup operation.

A-1.3.5 VOLATILE ORGANIC COMPOUND BACT

VOCs are a product of incomplete combustion of natural gas. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The primary technologies identified for reducing VOC emissions from the NGCC combustion turbines are oxidation catalysts and GCPs. A survey of the RBLC database indicated that good combustion control and burning clean fuel are the VOC control technologies primarily determined to be BACT.

A-1.3.5.1 Identify Control Technologies

Two technologies were identified as potentially applicable to the NGCC combustion turbines for control of VOC emissions:

<u>Combustion Process Controls</u>

- GCPs

<u>Post Combustion Controls</u>

- Oxidation Catalysts

A-1.3.5.2 Evaluate Technical Feasibility

Good Combustion Practices

GCPs applied to the proposed NGCC combustion turbines can achieve VOC emission levels below 3 ppmvd (at 15 percent O_2) based on data provided by GE Energy. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. This technology is commonly applied to NGCC combustion turbines, is considered technically feasible, and is considered the baseline control technology for VOC emissions.

Oxidation Catalyst

As discussed in Section A-1.4.2, catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC as well as CO, reducing emissions of both. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90 percent control for CO. It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). Oxidation catalyst systems are considered technically feasible for controlling VOC emissions from an NGCC combustion turbine.

A-1.3.5.3 Select Control Technology

Catalytic oxidation in conjunction with GCPs is proposed as BACT for VOCs emitted by and NGCC combustion turbine. These practices will meet a VOC emission limit of 0.0016 lb/MMBtu (as CH_4) when operated at full load and, 0.005 lb/MMBtu (as CH_4) when operated at partial loads. This equates to approximately 1 ppmvd at 15 percent O_2 in the stack gases at full load (with or without duct firing), and 3 ppmvd at 15 percent O_2 at 60 percent load.

A-1.3.6 PARTICULATE MATTER BACT

Particulate matter (PM, PM_{10}, and $PM_{2.5}$) emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low PM emissions. Virtually all emitted PM is PM_{10} and most is believed to be $PM_{2.5}$.

The EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for PM control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas. Use of GCPs and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

Use of pipeline natural gas and good combustion control is proposed as BACT for PM/PM_{10} emissions from the proposed combustion turbines. These operational controls will limit combined filterable and condensable PM/PM_{10} emissions to 19.0 lb/hr (per unit).

A-1.3.7 SULFUR DIOXIDE AND SULFURIC ACID MIST BACT

A-1.3.7.1 Identify Control Technologies

SO_2 emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of natural gas in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

Pre-Combustion Process Controls

- Use of low-sulfur fuel

Post-Combustion Controls

- Flue Gas Desulfurization (FGD)

Use of Low-Sulfur Fuel

Natural gas contains sulfur as hydrogen sulfide (H_2S), carbonyl sulfide (COS), dimethyl sulfide (DMS), and various mercaptans, but at extremely low concentrations. Natural gas is generally considered a low-sulfur fuel, and on-site treatment to remove additional sulfur, while technically feasible, would not be cost-effective.

Flue Gas Desulfurization

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional pulverized coal plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal.

A-1.3.7.2 Evaluate Technical Feasibility

The use of an FGD system to control SO_2 emissions from an NGCC combustion turbine is technically feasible in theory, but infeasible in practice. The pressure drop introduced by the FGD system could not be overcome by the combustion turbine without the addition of an induced draft fan, which would cause problems with the air/fuel mixture in the combustion turbine combustor. As a result, FGD technology is considered technically infeasible for controlling SO_2 emissions from an NGCC combustion turbine.

A-1.3.7.3 Select Control Technology

The applicant proposes that BACT for control of SO_2 emissions from the proposed NGCC combustion turbines be defined as treatment of the use of pipeline natural gas, which is considered a low-sulfur fuel.

A-1.3.8 TOXIC AIR POLLUTANT BACT

TAP emissions from natural gas-fired combustion sources consist of unburned hydrocarbons as well as inert and reactive contaminants in the natural gas. As a result, BACT for TAPs from natural gas-fired combustion turbines is generally considered to be the same as BACT for VOCs and PM from the same source (typically good combustion practices). Studies have also shown that emissions of some TAPs (such as formaldehyde) are oxidized by the oxidation catalyst that is proposed as BACT for CO and VOCs.

A-1.4 AUXILIARY BOILER BACT ANALYSIS

A-1.4.1 PROCESS DESCRIPTION

One auxiliary boiler will serve the two proposed NGCC combustion turbines and the proposed steam turbine by providing steam for pre-startup equipment heating, as well as other miscellaneous services when steam is not available from the HRSGs. The auxiliary boiler will have a maximum rated heat input less than 30 MMBtu/hr, and will be fueled only by pipeline quality natural gas.

Pollutant emissions from natural gas boiler units include NO_x, PM_{10}, $PM_{2.5}$, CO, SO_2, and VOCs. Annual operation of the boiler will be equal to or less than 2,500 hours of the year at maximum capacity.

A-1.4.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. Table A-1-3 lists a number of recent BACT determinations in recent years for auxiliary and industrial boiler equipment. The RBLC database survey results indicate that available BACT options for the pollutants emitted from auxiliary boilers include:

- Good Combustion Practices
- Staged Air/Fuel Combustion or Overfire Air Injection (OFA)
- Low-NO_x burners (LNB)
- Ultra-Low-NO_x burners (ULNB)
- Oxidation Catalysts
- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Low sulfur fuels

A-1.4.3 OXIDES OF NITROGEN BACT

Several combustion and post-combustion controls are commercially available for the auxiliary boiler. These controls include staged air/fuel combustion, low-NO_x burners, flue gas recirculation, and SCR. The range of BACT NO_x emission limits for recently permitted auxiliary boilers (since 2004) is from 0.011 lb/MMBtu to 0.37 lb/MMBtu.

TABLE A-1-3
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
OH-0310	02-07-08	Meigs County, OH	American Municipal Power	Auxiliary Boiler	150 MMBtu/hr	NO_X – 21 lb/hr (0.014 lb/MMBtu) SO_X – 0.09 lb/hr (0.00060 lb/MMBtu) CO – 12.6 lb/hr (0.084 lb/MMBtu) VOC – 0.83 lb/hr (0.0055 lb/MMBtu) PM_{10} – 1.14 lb/hr (0.0076 lb/MMBtu) 10% Opacity	Not Described	BACT-PSD; RACT (VE)
GA-0127	01-07-08	Cobb County, GA	Southern Company/Georgia Power	Auxiliary Boilers	200 MMBtu/hr (each of three units)	CO – 0.037 lb/MMBtu VOC – 0.0051 lb/MMBtu	Not Described	LAER (VOC); BACT-PSD (CO)
TX-0499	07-24-06	McClennan County, TX	Sandy Creek Energy Assoc.	Auxiliary Boiler	175 MMBtu/hr	NO_X – 1.8 lb/hr (0.010 lb/MMBtu) SO_X – 0.11 lb/hr (0.00063 lb/MMBtu) CO – 6.1 lb/hr (0.035 lb/MMBtu) VOC – 0.7 lb/hr (0.0040 lb/MMBtu) PM_{10} – 0.88 lb/hr (0.0050 lb/MMBtu)	Not Described	BACT-PSD

TABLE A-1-3 (Continued)
RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0066	05-16-06	Ramsey County, MN	XCEL Energy	Auxiliary Boiler	160 MMBtu/hr	CO – 0.08 lb/MMBtu VOC – 0.005 lb/MMBtu	Good Combustion	BACT-PSD; MACT (CO)
MN-0062	12-22-05	Sibley County, MN	Heartland Corn Products	Boiler	198 MMBtu/hr	NO_X – 0.04 lb/MMBtu CO – 0.04 lb/MMBtu	Not Described	BACT-PSD
NC-0101	09-25-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Auxiliary Boiler	110.2 MMBtu/hr	NO_X – 15.13 lb/hr (0.14 lb/MMBtu) SO_X – 0.61 lb/hr (0.0055 lb/MMBtu) CO – 9.08 lb/hr (0.082 lb/MMBtu) VOC – 0.59 lb/hr (0.0054 lb/MMBtu) PM_{10} – 0.82 lb/hr (0.007 lb/MMBtu)	Low NO_X burners, Good Combustion Control, and Clean Burning, Low-Sulfur Fuel	BACT-PSD
WI-0228	10-19-04	Marathon County, WI	Wisconsin Public Service	Auxiliary Boiler	229.8 MMBtu/hr	PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.0006 lb/MMBtu NO_X – 0.10 lb/MMBtu CO – 0.08 lb/MMBtu VOC – 0.0054 lb/MMBtu Hg - 0.0001 lb/hr	Low NOx burners, Good Combustion Practices, and Natural Gas Fuel.	BACT-PSD
NE-0024	06-22-04	Washington County, NE	Cargill, Inc.	Boiler	198 MMBtu/hr	NO_X – 0.07 lb/MMBtu 20% Opacity	Low NO_X burners and Induced Draft Flue Gas Recirculation	Other Case-by-Case
MS-0069	06-08-04	Harrison County, MS	E.I. Dupont De Nemours	Boiler	231 MMBtu/hr	PM_{10} – 1.76 lb/hr (0.0076 lb/MMBtu) NO_X – 0.09 lb/MMBtu	Low NO_X burners with FGR and Natural Gas Fuel	BACT-PSD

TABLE A-1-3 (Continued)
RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
ID-0015	04-05-04	Power County, ID	JR Simplot Company	Boiler	175 MMBtu/hr	NO_X – 7 lb/hr (0.040 lb/MMBtu)	Low NO_X Burners	RACT
WV-0023	03-02-04	Monongahela County, WV	Longview Power, LLC	Auxiliary Boiler	225 MMBtu/hr	CO – 0.04 lb/MMBtu NO_X – 0.0980 lb/MMBtu PM_{10} – 0.0022 lb/MMBtu SO_2 – 0.0040 lb/hr VOC – 0.0054 lb/MMBtu 10% opacity	Low NO_X Burners, Good Combustion Practices, Use of Clean, Low-Sulfur Natural Gas	BACT-PSD

A-1.4.3.1 Ranking of Available Control Technologies

The identified control technologies are considered technically feasible for gaseous fuel fired boilers. Consequently, these controls will be ranked and evaluated for each pollutant for which BACT is required. In top-down order of decreasing stringency, the feasible NO_x controls are listed with the approximate level of emission reduction afforded by each technology:

- Low-NO_x Burners with SCR 0.011 lb/MMBtu
- Ultra-Low-NO_x Burners 0.011 lb/MMBtu
- Low-NO_x Burners with FGR 0.020 lb/MMBtu
- Low-NO_x Burners with GCP 0.036 lb/MMBtu
- FGR Alone 0.20 lb/MMBtu
- Staged air/fuel or OFA 0.25 lb/MMBtu
- GCP, Conventional Burners 0.40 lb/MMBtu

A-1.4.3.2 Proposed BACT Limits and Control Option

Grays Harbor Energy proposes BACT for NO_x emissions from the natural gas-fired auxiliary boiler be good combustion practices with Ultra-Low-NO_x burners. Boiler vendor information indicates that the hourly emissions for this unit with these technologies will be about 0.011 lb/MMBtu NO_x (equivalent to approximately 9 ppmvd at 3 percent O_2) at loads greater than 75 percent. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT NO_x limit for emissions from the auxiliary boiler.

A-1.4.4 CARBON MONOXIDE BACT

Only one post-combustion control is commercially available for the auxiliary boiler. This control is the implementation of an oxidation catalyst module. Based on the RBLC review presented in Table A-1-3, the range of BACT CO emission limits for recently permitted auxiliary boilers (since 2004) is from 0.037 lb/MMBtu to 0.08 lb/MMBtu. BACT for CO on most units is GCP.

A-1.4.4.1 Ranking of Available Control Technologies

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for gaseous fuel fired boilers. In top-down order of decreasing stringency, the feasible CO controls are listed with the approximate level of control that could be achieved:

- Oxidation Catalyst and GCP 90% control
- GCP 0.037 lb/MMBtu (BACT baseline)

A-1.4.4.2 Consideration of Energy, Environmental and Cost Factors

The use of oxidation catalyst modules as add-on emission control is available and technically feasible for reduction in CO emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_x burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the effects of spent catalyst module disposal.

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. Since the boiler is not continuously operated, but rather used during relatively infrequent start-up cycles, the emissions abated can be shown to not warrant the investment in capital and operating costs. An annualized cost analysis for the proposed auxiliary boiler is provided to demonstrate this cost barrier. The findings of these cost analyses are summarized in Table A-1-4 and detailed in Table A-1-9.

TABLE A-1-4
ECONOMIC ANALYSIS OF POST-COMBUSTION CO CONTROLS FOR AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
Catalytic Oxidizer	90% reduction (0.0037 lb/MMBtu)	$273,400	$76,419	1.22 (reduction)	$62,600
Baseline Option (GCP)	0.037 lb/MMBtu	---	---	1.36 (baseline)	---

The add-on CO control technology for the auxiliary boiler would be cost prohibitive in terms of cost per ton abated. The implementation of a catalytic oxidizer module has an estimated annualized cost of over $76,000, and provides a reduction of 1.22 tons per year, compared with the baseline option of GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be not less than $62,000 per ton CO removed.

A-1.4.4.3 Proposed BACT Limits and Control Option

As illustrated in Table A-1-4, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks, leads to the proposed BACT option of GCP for CO emissions. Grays Harbor Energy proposes that BACT for CO from the auxiliary boiler is 0.037 lb/MMBtu (approximately 50 ppmvd), 3-hour average.

A-1.4.5 SULFUR DIOXIDE, VOLATILE ORGANIC COMPOUND, AND PARTICULATE MATTER BACT

A-1.4.5.1 Ranking of Available Control Technologies

For these pollutants, the commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas, and GCP. Based on review of the RBLC database in Table A-1-3, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_x = 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- VOC = 0.0044 lb/MMBtu to 0.0054 lb/MMBtu
- PM_{10} = 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the auxiliary boiler, so further evaluation is unnecessary.

A-1.4.5.2 Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low annual emissions of SO_2, VOC, PM_{10}, and $PM_{2.5}$ meaning that investment in add-on controls would not be cost effective even if they were feasible. Therefore, the use of pipeline natural gas and GCP are proposed as BACT for the auxiliary boiler, and no emission rates are proposed as BACT limits for SO_2, VOCs, PM_{10}, and $PM_{2.5}$. Mass balance calculations based on the sulfur content of the expected source of natural gas indicates SO_2 emissions will be approximately 0.0058 lb/MMBtu (hourly average), 0.0054 lb/MMBtu (24-hour average), and 0.0029 lb/MMBtu (annual average). Boiler vendor information indicates that hourly VOC and PM_{10} emissions are 0.004 lb and 0.005 lb/MMBtu, respectively. $PM_{2.5}$ emissions were based on the filterable portion of the calculated PM_{10} emission rate using fraction provided in AP-42 Section 1.4.

A-1.4.6 TOXIC AIR POLLUTANT BACT

TAP emissions from natural gas-fired combustion sources consist of unburned hydrocarbons as well as inert and reactive contaminants in the natural gas. As a result, BACT for TAPs from natural gas-fired boilers is generally considered to be the same as BACT for VOCs and PM from the same source.

A-1.5 COOLING TOWER BACT ANALYSIS

A-1.5.1 PROCESS DESCRIPTION

The cooling system proposed for the expansion project consists of a circulating water system that will utilize two five-cell mechanical draft cooling tower to support operations of the steam turbine generator. Wet (evaporative) cooling towers emit aqueous aerosol “drift” particles that evaporate to leave crystallized solid particles that are considered PM_{10} emissions. The proposed control technology for PM_{10} is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere.

A-1.5.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Electrical generating facilities, refineries, and other large chemical processing plants utilize wet mechanical draft cooling towers for heat rejection. This portion of the proposed facility can be viewed as substantially similar to such processes.

Review of the federal RBLC database and recent Washington state permits for large-scale cooling towers indicates that high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, which attempt to optimize droplet impingement with minimal pressure drop.

Table A-1-5 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM_{10} emissions. Compared to “conventional” drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design will be based on 12 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 12 times that of the introduced make-up water), and a total dissolved solids (TDS) concentration of 200 ppmw in the make up water, which translates to a cooling water TDS concentration of 2,400 ppmw.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined cycle plants in arid climates, usually because of concerns other than air emissions. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

A-1.5.3 INFEASIBLE CONTROL MEASURES

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature.

TABLE A-1-5
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
LA-0148	05-28-08	Red River Parish, LA	Red River Environmental Products, LLC	Cooling Towers	10,750 gal/min	PM – 0.41 lb/hr	Drift Elimination System	BACT-PSD
LA-0224	03-20-08	Caddo Parish, LA	Southwest Electric Power Company	Cooling Tower	140,000 gal/min	PM – 1.4 lb/hr	Mist Eliminators	BACT-PSD
LA-0221	11-30-07	St. Charles Parish, LA	Entergy Louisiana, LLC	Cooling Tower	5,000 gal/min	PM – 0.5 lb/hr	Drift Eliminator with 99.999% Control Eff.	BACT-PSD
ND-0024	09-14-07	Stutsman County, ND	Great River Energy	Cooling Tower	80,000 gal/min	PM – 0.0005% of cooling water	Drift Eliminator	BACT-PSD
MN-0070	09-07-07	Itasca County, MN	Minnesota Steel Industries, LLC	Cooling Tower	Not Provided	PM, PM_{10} – 0.005% drift rate	Design to minimize drift	BACT-PSD
IA-0089	08-08-07	Chickasaw County, IA	Homeland Energy Solutions, LLC	Cooling Tower	5,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator/ Demister	BACT-PSD
IA-0088	06-29-07	Linn County, IA	Archer Daniels Midland	Cooling Tower	150,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator	BACT-PSD
LA-0211	12-27-06	St. John the Baptist Parish, LA	Marathon Petroleum Co., LLC	Cooling Towers	30,000 & 96,250 gal/min	PM_{10} – 0.005% drift	High Efficiency Drift Eliminators	BACT-PSD
FL-0294	12-22-06	Pasco County, FL	Progress Energy Florida	Cooling Towers	660,000 gal/min	PM – 108 tons/year	Drift Eliminators	BACT-PSD

TABLE A-1-5 (Continued)
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
WV-0024	04-26-06	Greenbrier County, WV	Western Greenbrier Co-Generation, LLC	Cooling Tower	55,000 gal/min	PM – 0.79 lb/hr	Drift Eliminators with 0.0005% drift	BACT-PSD
IA-0082	04-19-06	Cerro Gordo County, IA	Golden Grain Energy	Cooling Tower	NA	PM_{10} – 1.33 lb/hr	Mist Eliminators	BACT-PSD
LA-0202	02-23-06	Rapides Parish, LA	Cleco Power, LLC	Cooling Tower	301,874 gal/min	PM_{10} – 1.13 lb/hr 3.31 tons/year	Drift Eliminators	BACT-PSD
OR-0041	08-08-05	Umatilla County, OR	Diamond Wanapa I LP	Cooling Tower	6.2 ft^3/sec	PM – 3532 ppmw	High Efficiency 0.0005% Drift Eliminators; Limit TDS to < 3,532 PPMW.	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Cooling tower	140,650 gal/min	PM – NA PM_{10} - NA	RACT is drift eliminators to achieve 0.0005 % drift or less.	BACT-PSD
LA-0192	06-06-05	Orleans Parish, LA	Cresent City Power LLC	Cooling Tower	290,200 gal.min	PM_{10} – 2.61 lb/hr	TDS = 30,000 PPM 0.0001% drift annual average (Marley Excel Drift Eliminators)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IA	Auburn Nugget	Cooling Tower	23,450 gal/min	PM – 0.0050% of Throughput 20% opacity	NA	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Cooling Tower	NA	PM_{10} – 0.0005% drift	Drift Eliminators	BACT-PSD

TABLE A-1-5 (Continued)
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels LLC	Cooling Tower	NA	PM – 1.6 lb/hr	High Efficiency Drift Eliminators	BACT-PSD
NY-0093	03-31-05	Nassau County, NY	Igen-Nassau Energy Corporation	Cooling Tower	NA	PM_{10} – 0.0005% drift	NA	BACT-PSD
NE-0031	03-09-05	Otoe County, NE	Omaha Public Power District OPPD	Cooling Tower	NA	PM_{10} – 0.0010 lb/hr	High Efficiency Mist Eliminators - 0.0005% drift	BACT-PSD
WA		Cherry Point	BP Refinery	Cogeneration Cooling Tower	NA	7.2 tpy	0.001% drift	BACT-PSD
WA		Hanging Rock Energy Facility	Duke Energy	Combined Cycle Unit Cooling Tower	NA	3.6 lb/hr	Drift Eliminators	BACT-PSD
WA		Mint Farm Generation		Combined Cycle Unit Cooling Tower	NA	1.08 tpy	Drift Eliminators	BACT-PSD
WA		Wallula Power Project		Combined Cycle Unit Cooling Tower	NA	3.7 lb/hr	Water pre-treatment and 0.0005% drift rate	LAER

Because of the high capital cost and process design changes involved in the use of a dry cooling tower, that option would not be cost effective and is removed from consideration.

A-1.5.4 RANKING OF AVAILABLE CONTROL MEASURES

Because all of the commercially available options that could form the basis for a BACT emission limit for PM_{10} from the cooling tower are also technically feasible, this section will rank these options. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In "top down" order from most to less stringent, the potentially available candidate control techniques are:

- Combinations of high-efficiency drift eliminators and TDS limit
- High-Efficiency drift eliminators to control drift to as low as 0.0005% of circulating flow
- High-efficiency drift eliminators, as low as 0.001% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

A-1.5.5 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT for cooling towers in current permits.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to "conventional" specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 12-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM_{10} abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce

TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

A-1.5.6 PROPOSED BACT LIMITS AND CONTROL OPTION

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the proposed cooling towers is use of drift eliminators achieving a maximum drift of 0.0005 percent of the circulating water.

A-1.6 INTERNAL COMBUSTION ENGINE BACT ANALYSIS

A-1.6.1 PROCESS DESCRIPTION

A pump powered by a nominal 275 hp diesel engine will be installed to provide water for fire suppression when power is from the grid is not available to run the electric firewater system. In addition, a 600 hp diesel-fueled engine will drive a 400 kw generator to provide emergency power when power from the grid is not available. Both engines will burn ultra-low sulfur distillate oil. Other than plant emergency situations, each engine will be operated no more than 26 hours per year for routine testing, maintenance, and inspection purposes.

Although the engine makes and models have not yet been specified, the emission standards for stationary engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS) were used to calculate criteria pollutant emissions.[3]

A-1.6.2 OXIDES OF NITROGEN BACT

A-1.6.2.1 Available Control Technologies and Technical Feasibility

There are a limited number of technically-feasible NO_x control technologies that are commercially available for internal combustion engines. Two general types of control options have emerged as technically feasible: combustion process modifications, and post combustion controls. In practice, the high temperature and relatively low volumetric flow of the engine exhaust eliminates post-combustion controls from consideration.

Combustion Process Modifications - This option is incorporated in the engine design. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

Selective Catalytic Reduction (SCR) - In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module downstream of the engine exhaust. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly

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[3] Subpart IIII limits the sum of NO_x and VOC emissions, we have conservatively assumed the engine would emit both NO_X and VOC and the standard for the sum of the two pollutants.

into the exhaust stream. Another potentially available technology that has been eliminated from consideration on the grounds that it is technically infeasible is:

Non-Selective Catalytic Reduction (NSCR) – Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than four percent oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

A-1.6.2.2 Energy and Environmental Considerations

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the engines proposed for the project will operate only for brief testing and maintenance checks; Subpart IIII limits these checks to 100 hours per year but this application proposes no more than 26 hours of operation (per engine) per year. The minimal operation significantly reduces the effectiveness of the post-combustion controls.

Further, it should be assumed that ammonia emissions will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

TABLE A-1-6
RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES ≤ 500 HP

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
LA-0224	03-20-08	Caddo Parish, LA	Southwest Electric Power Co.	Diesel Fire Pump	310 HP	NO_x – 9.61 lb/hr CO – 2.07 lb/hr PM_{10} – 0.68 lb/hr SO_2 – 0.64 lb/hr VOC – 0.77 lb/hr	Low-Sulfur fuel, limited operation hours, and proper engine maintenance	BACT-PSD
MN-0070	09-07-07	Itasca County, MN	Minnesota Steel Industries, LLC	Diesel Fire Water Pumps	Not Provided	SO_2 – 0.05% in fuel VE – 5%	Limited Sulfur in fuel, limited hours	BACT-PSD
CA-1144	04-25-07	Riverside County, CA	Caithness Blythe II, LLC	Fire Pump	303 HP	NO_x – 7.5 lb/hr CO – 0.7 lb/hr PM_{10} – 0.1 lb/hr	Fuel with less than 0.05% sulfur by weight	BACT-PSD
IA-0084	11-30-06	Clinton County, IA	ADM Corn Processing	Fire Pump Engine	500 HP	VOC – 3 g/HP-hr	GCP	BACT-PSD
OK-0110	10-21-05	Muskogee County, OK	Dalitalia, LLC	Emergency Generator	Not Provided	CO – 0.0067 lb/HP-hr PM_{10} – 0.0022 lb/HP-hr VOC – 0.0025 lb/HP-hr	GCP	Not Prov.
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Emergency Generator and Firewater Pump	11.40 MMBtu/hr	NO_x – 36.48 lb/hr CO – 9.69 lb/hr PM_{10} – 1.14 lb/hr SO_2 – 0.58 lb/hr VOC – 1.04 lb/hr	Emergency use only	BACT-PSD
LA-0192	06-06-05	Orleans County, LA	Cresent City Power, LLC	Firewater Pump	425 HP	NO_x – 8.9 lb/hr CO – 1.88 lb/hr PM_{10} – 0.14 lb/hr SO_2 – 0.61 lb/hr VOC – 0.05 lb/hr	Good engine design and proper operating practices	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock ,LLC	Firewater Pump	265 HP	NO_x – 8.2 lb/hr CO – 1.8 lb/hr PM – 0.66 lb/hr SO_2 – 0.10 lb/hr VOC – 0.66 lb/hr	500 hr/yr	BACT-PSD

When SCR or any add-on emission control technology is used, additional auxiliary equipment such as pumps and motors must be added. Also, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases reduce the net energy efficiency of the plant. In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or the use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

A-1.6.2.3 Ranking of Control Options

With regard to NO_x emission abatement, the ranking of the technically-feasible options is straightforward. The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90 percent reduction in NO_x mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

A-1.6.2.4 Economic Analysis for Controls

Since advanced NO_x controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost. Table A-1-7 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

TABLE A-1-7
ECONOMIC ANALYSIS OF POST-COMBUSTION SCR CONTROLS FOR IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% reduction)	Estimated Total Capital Investment [1]	Estimated Annualized Costs [2] ($/yr)	Emissions Reduction (tons/yr)	Cost Effectiveness ($ / ton)
275 hp Fire Water Pump	0.0018 tons/yr	$243,844	$78,900	0.016	$4,970,000
600 hp Emer. Gen.	0.0051 tons/yr	$243,844	$78,900	0.046	$1,709,000

[1] Estimated capital cost for SCR control based on 300 hp diesel engine. Cost estimate should be conservative for larger emergency generator engine.

[2] Annualized costs include capital recovery (10 year equipment life and 7 percent interest), maintenance, and operation costs.

As shown in Table A-1-7, the annualized operating costs for addition of SCR to an IC engine would be about $79,000 per year. Assuming a 90 percent control efficiency, the SCR controls would reduce up to 0.05 tons of NO_X per year for the emergency generator. The cost effectiveness results in more than $1,700,000 per ton removed, which represents a prohibitively high cost for this BACT option.

A-1.6.2.5 Proposed BACT

SCR has been shown to be cost prohibitive as BACT for the project engines. The proposed BACT for the proposed engines is the combustion modifications supplied as standard equipment with the candidate types of engines which enable the manufacturer to certify the engine under Subpart IIII.

A-1.6.3 CARBON MONOXIDE AND VOLATILE ORGANIC COMPOUND BACT

NO_x, CO and VOC emissions for the engines were calculated using the stationary fire pump engine standards in Subpart IIII.[4] The engines selected for this project would be certified by the manufacturer to achieve the applicable standards in Subpart IIII, and would be operated less than 26 hours per year in a non-emergency mode, as required by Subpart IIII.

A-1.6.3.1 Technically-Feasible Controls

For CO emissions, the commercially available control means for IC engines are:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO and VOCs diffuse through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reactions on the catalyst surface forms carbon dioxide and water. Typical vendor indications are that 95 percent reduction in CO and 50 percent reduction in VOC emissions should be achieved.

A-1.6.3.2 Cost Effectiveness Analysis

Table A-1-7 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

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[4] Subpart IIII limits the sum of NO_x and VOC emissions, we have conservatively assumed the engine would emit both NO_X and VOC and the standard for the sum of the two pollutants.

TABLE A-1-8
ECONOMIC ANALYSIS OF POST-COMBUSTION CATALYTIC OXIDATION CONTROLS FOR IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% CO and 50% VOC reductions)	Estimated Annualized Costs [1] ($/yr)	Total Emissions Reduction (tons/yr)	Cost Effectiveness ($ / ton)
275 hp Fire Water Pump	0.00076 tons CO/yr 0.0088 tons VOC/yr	$15,616	0.023	$669,000
600 hp Emer. Gen.	0.0022 tons CO/yr 0.026 tons VOC/yr	$29,241	0.068	$428,000

[1] Annualized costs estimated by IC engine exhaust flow rates (1,952 cfm – fire water pump and 3,655 cfm – emergency generator) and a conservative annualized cost for the catalytic oxidation controls of $8/scfm (EPA-452/F-03-018).

As shown in Table A-1-8, the low end of estimated annualized operating costs for addition of catalytic oxidation to would be approximately $16,000 – 29,000 for the IC engines. Assuming 95 percent CO and 50 percent VOC control efficiencies, the catalytic oxidation controls would reduce up to 0.068 tons of total CO and VOC emissions per year for the emergency generator. The cost effectiveness results in more than $428,000 per ton removed, which represents a prohibitively high cost for this BACT option.

A-1.6.3.3 Proposed BACT

Catalytic oxidation has been shown to be cost prohibitive as BACT for the engines proposed for this project. Grays Harbor Energy asserts that BACT is the combustion modifications supplied by the manufacturer as standard equipment that enable the engines to meet the emission standards in Subpart IIII. Annual emissions would be limited by restricting non-emergency hours of operation to less than 26 hours per year.

A-1.6.4 SULFUR DIOXIDE AND PARTICLUATE MATTER BACT

The fire pump engine proposed for the project will have annual emissions of 0.000043 tons of SO_2, 0.0024 tons of PM_{10}, and 0.0020 tons of $PM_{2.5}$. The emergency generator engine proposed for the project will have annual emissions of 0.000095 tons of SO_2, 0.0026 tons of PM_{10}, and 0.0021 tons of $PM_{2.5}$.The SO_2 emission rate was calculated using the equation provided in Table 3.4-1 of AP-42 Section 3.4 (Large Stationary Diesel and All Stationary Dual-Fuel Engines) and ultra low sulfur diesel fuel content of 15 ppm by weight. PM_{10} emissions were based on Subpart IIII standards, and $PM_{2.5}$ emissions were based on the calculated PM_{10} emission rate and the ratio of the $PM_{2.5}$ and PM_{10} emission factors provided in AP-42 Section 3.4. Given these low emissions, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of engines certified by manufacturers to meet Subpart IIII emission standards, use of ULSD fuel, and limitation of non-emergency operation to no more than 26 hours per year will provide relatively low emissions of SO_2, PM_{10}, and $PM_{2.5}$ and are proposed as BACT measures for these pollutants.

TABLE A-1-9
CATALYTIC OXIDIZER COST EFFECTIVENESS CALCULATIONS
Natural Gas-Fired Auxiliary Boiler - 30 MMBtu/hr

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. Primary Equipment (Fixed Bed Catalytic, 50% Heat Recovery)	$139,673	OAQPS
b. Catalyst Replacement Allowance	$5,000	Engineering Estimate
b. Instrumentation (0.1*a)	$13,967	OAQPS
c. Sales tax (0.03*a)	$4,190	OAQPS
d. Freight (0.05*a)	$6,984	OAQPS
Total Purchases Equipment Cost [TEC]	$169,814	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports (0.08*TEC)	$13,585	OAQPS
b. Handling and Erection (0.14*TEC)	$23,774	OAQPS
c. Electrical (0.04*TEC)	$6,793	OAQPS
d. Piping (0.02*TEC)	$3,396	OAQPS
e. Insulation for Ductwork (0.01*TEC)	$1,698	OAQPS
f. Painting (0.01*TEC)	$1,698	OAQPS
Total Direct Installation Costs [TDC](I+II)	$50,944	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering and Supervision (0.10*TEC)	$16,981	OAQPS
b. Construction and Field Expenses (0.05*TEC)	$8,491	OAQPS
c. Contractor Fee (0.10*TEC)	$16,981	OAQPS
d. Contingencies (0.03*TEC)	$5,094	OAQPS
IV. Other Indirect Costs		
a. Startup and Testing (0.03*TEC)	$5,094	OAQPS
Total Indirect Costs [TIC](III+IV)	$52,642	*Calculation*
Total Capital Costs [TCC] (TEC+TDC+TIC)	$273,400	*Calculation*
Total Annualized Capital Costs [TACC] (10 years @ 7% interest)	**$38,926**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT OPERATING COSTS (DOC)		
I. Labor for operations ($35.29/person-hour)(0.5 hr/shift)(1 shifts/8 hours)(2,500 hours/yr)	$5,514	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)	$827	OAQPS
III. Maintenance Labor ($35.29/person-hour)(0.5 hr/shift)(1 shifts/8 hours)(2,500 hours/yr)	$5,514	Engineering Estimate
IV. Maintenance Materials (100% of maintenance labor)	$5,514	OAQPS
V. Utility costs		
a. Electricity - Fan (12 kWh)($0.08/kW-hr)(2,500 hr/yr)	$1,500	Engineering Estimate
VI. Fuel Penalty (none)	$0	
VII. Waste Disposal	$0	
INDIRECT OPERATING COSTS (IOC)		
VII. Overhead (0.6*O&M costs(I-IV of DOC)	$10,422	OAQPS
VIII. Administration (0.02*TCC)	$5,468	OAQPS
IX. Insurance (0.01*TCC)	$2,734	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	**$37,493**	*Calculation*
TOTAL ANNUALIZED COSTS [TAC_{OC}] (TACC+TDIAC)	**$76,419**	*Calculation*

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quiality Planning and Standards (OAQPS).

Calculation The calculated exhaust from the boiler is 4,966 dscfm. Operating approximately 2,500 hours/year