NOTE: The proposed ASCPC PM limit of 0.011lb/MMBtu, the VOC limit of 0.00034 lb/MMBtu and the HF limit of 0.00017 lb/MMBtu have all been established through the case-by case-MACT included in Appendix J. The proposed Auxiliary Boiler VOC limit of 0.0013 lb/MMBtu is based on the MACT demonstration in Appendix K. These MACT emission limits supersede the ASCPC and Auxiliary Boiler BACT determinations included in this section. They are included in the Summary tables for the ASCPC and auxiliary boilers.

5.0 CONTROL TECHNOLOGY REVIEW

The proposed project is considered a "major modification" at a "major stationary source" as defined in the PSD regulations at 40 CFR 52.21 because there will be a significant increase in at least one regulated NSR pollutant, specifically PM, $PM_{10}/PM_{2.5}$, NO_x, SO_2, CO, VOC, H_2SO_4, and Fluorides emissions as a result of installing the new ASCPC unit. Therefore, the requirements for best available control technology (BACT) found in 40 CFR 52.21(j) will be applicable to control emissions of PM, $PM_{10}/PM_{2.5}$, NO_x, SO_2, CO, VOC, H_2SO_4, and Fluorides (as HF) from the proposed modifications presented in the previous sections. The BACT analyses contained in this application were performed in accordance with the USEPA's recommended top-down procedure outlined in the New Source Review Workshop Manual (Draft 1990) and set forth in Section 165(a)(4) of the federal CAA, the implementing regulations at 40 CFR 52.21(b)(12), as well as MDEQ – AQD Operational Memorandum No. 20. While it is nonbinding guidance, the methodology in Op. Memo 20 generally follows the USEPA's recommended top-down procedure outlined in the New Source Review Workshop Manual (Draft 1990). Unless noted otherwise, all BACT limits established in this application represent emissions under normal operating conditions.

5.1 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Any new major source or major modification to an existing major source is required to perform an evaluation of control technologies to ensure that emissions of each regulated NSR pollutant subject to review is minimized to the maximum extent achievable taking into consideration several factors. In addition, BACT is preferably defined as an emission limit, not a specific control technology as identified in the definition (40 CFR 52.21(b)(12)). Only if such an emission limit is infeasible (e.g., non-measurable and thus unenforceable) is BACT a technique, design, equipment or work practice.

> ***Best Available Control Technology*** *means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is*

> *achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The USEPA has established a five-step procedure for determining the appropriate BACT limit for each subject pollutant that starts with the most stringent emission limit and lists all control technologies. This is referred to as "Top-Down" BACT and includes the following 5 steps as outlined in the Draft New Source Review Manual, dated 1990:

1) Identify All Control Technologies
2) Evaluation of All Control Technologies and Eliminating All Infeasible Options
3) Rank Remaining Control Technologies by Control Effectiveness
4) Evaluate Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts of Control Options
5) Select BACT Based upon Consideration of Impacts

STEP 1 – Identify All Control Technologies

The first step in the top down procedure is to identify all control technologies and emission reduction options for each subject pollutant. Consumers is employing advanced supercritical pulverized coal-fired technology for the proposed project. In order to identify the appropriate control technologies, the following sources of information were referenced:

- USEPA RACT/BACT/LAER Clearinghouse (RBLC)
- USEPA Control Technology Center (CTC)
- Recent Permit Actions by MDEQ and other States

- Vendor Information
- Project Experience from all parties associated with this project, including NTH Consultants, Ltd., Cummins & Barnard, Inc., and Consumers Energy
- USEPA Region 7 National Coal-Fired Utility Projects Spreadsheet

STEP 2 – Eliminate Technically Infeasible Control Technologies

The second step in performing the top-down BACT analysis is to eliminate all technically infeasible options. The determination that a control technology is technically infeasible is source-specific and based upon physical, chemical, and engineering principles. Two key concepts in determining whether an undemonstrated technology is feasible are: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration.

STEP 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the top-down BACT analysis is to rank all remaining control technologies with respect to control effectiveness. The control technologies are ranked in order of control effectiveness (i.e., by emission limit or removal efficiency, as applicable) and are pollutant-specific. The emission limit or removal efficiency used in the ranking process is the level the technology has demonstrated it can consistently achieve under reasonably foreseeable worst-case conditions with an adequate margin of safety. It is not a limit or removal efficiency that can sometimes be achieved.

If the top-ranked control technology option is chosen, the BACT analysis is complete and no further information regarding economic, environmental, and energy impacts are required. However, if the top-ranked option is not chosen, an assessment of economic, environmental, and energy impacts are performed to evaluate the most effective controls in step 4.

STEP 4 – Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology in order to determine whether the energy, economic or environmental impacts from a given technology outweigh their benefits. Information including control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental and energy impacts are to be considered.

STEP 5 – Select BACT

The fifth, and final, step is selection of the BACT emission limit corresponding to the most stringent, and technically feasible technology that was not eliminated based upon adverse economic, environmental, and energy impacts.

USEPA's Air Pollution Control Cost Manual published in January 2002 (EPA/452/B-02-001) provides capital and annual operating cost factors for use in determining the economic impact of each control technology.

Finally, pursuant to 40 CFR 52.21(b)(12), the chosen BACT emission limit must not be less stringent than any applicable federal NSPS, NESHAP, or state-specific emission standard. The BACT emission limits chosen for this project are at least as stringent as applicable federal or state standards.

5.1.1 Startup, Shutdown, and Malfunction

The project proposes applicable work practice standards, such as good air pollution control practices and proper operation and maintenance, as BACT during startup, shutdown, and malfunctions. While the main boiler is proposed as a baseload unit and being permitted for unlimited annual operation, the unit will infrequently be required to shut down and start up depending on load requirements and system maintenance. The boiler will be designed to initially start up on clean emitting natural gas until the load on the boiler reaches approximately 10 percent, after which coal will be introduced into the boiler in combination with the startup fuel for stabilization, until the boiler reaches approximately 30 percent of load.

Startup of the boiler from cold conditions to full load is estimated to take between 8 and 12 hours. If the auxiliary boiler is used to maintain heat in the plant's systems, startup time is reduced. Natural gas fuel is used in the boiler igniters to slowly increase boiler metal temperatures. Once boiler load has increased beyond the minimum capacity of one coal mill (approximately 4 to 6 hours into startup), a coal mill is started and the boiler is operated on both natural gas fuel and coal. Once stable operation on coal has been established on two mills (approximately 25 percent load, 8 to 10 hours into startup), the natural gas fuel is discontinued and boiler load is increased as necessary using primarily coal fuel. As additional coal mills are started, natural gas fuel is briefly (less than an hour) used in the appropriate individual boiler ignitors to ensure safe startup of the mill.

Each component of an air quality control system has differing startup requirements before it becomes fully effective. For example, a fabric filter that controls PM/PM_{10} or a wet FGD that controls SO_2 becomes fully effective shortly after startup of the boiler. In contrast, an SCR that controls NO_x does not become fully effective until the flue gas temperature after the economizer of the boiler reaches approximately 600°F, which is critical for the injection of ammonia and the reactions that take place. The SCR has an operating temperature range of approximately 600°F to 800°F in effectively controlling NO_x and this temperature range needs to be closely adhered to avoid damaging the SCR catalyst or possible fouling of the air heater. The estimated time for the SCR to become fully effective is approximately 8 to 11 hours (between 25 to 50 percent load). As for CO and VOC control, good combustion controls are used. Good combustion controls begin to become effective at approximately 60 percent load when the boiler is tuned and it is achieving its steam temperature. The estimated time of good combustion controls is approximately 11 to 12 hours into startup.

As a practical and regulatory matter, a BACT determination, in addition to having to be technically feasible, must be enforceable. For the purposes of a BACT determination for periods of startup, shutdown, and malfunction, an important consideration to be made is whether an emission limit is enforceable as a practical matter as a BACT determination. Consideration of this issue relies heavily and primarily on whether emission measurements made during these transient events can be used to determine compliance with a specified emission limit.

For coal-fired boilers, emission tests using approved reference methods cannot be conducted with any suitable degree of reliability during startup, shutdown, and malfunction in order to serve as a reliable method of demonstrating compliance with an expressed BACT emission limit. This is similar and consistent with the regulatory provisions of the NSPS, where the operations during periods of startup, shutdown, and malfunction are not considered representative conditions for the purpose of conducting compliance performance tests. In other words, the use of an emission limit to establish BACT compliance during startup, shutdown, and malfunction is not considered enforceable as a practical matter. However, the regulatory definition of BACT envisioned these types of circumstances and provided for the use of applicable work practice standards such as good air pollution control practices and proper operation and maintenance as a basis for measurable and practicably enforceable compliance elements in lieu of emission standards. Consumers would develop, and submit to MDEQ, startup and shutdown plans describing good air pollution control practices for all emission units and control equipment, pursuant to a condition of the permit.

5.2 ASCPC BOILER BACT EVALUATION

A control technology review and BACT evaluation for all regulated NSR pollutants identified in Section 5.0 is required for the new ASCPC boiler. Consumers has reviewed recent permits and BACT determinations involving pulverized coal-fueled boilers, and other relevant information, for comparison to the emission limits proposed as BACT for this project. A comprehensive summary of recent BACT determinations is provided in Table D-4 while pollutant-specific determinations are summarized at the end of each section. The BACT emission limits proposed for the ASCPC boiler are consistent with recent PSD BACT limits established for similar projects. The sections that follow provided a detailed BACT analysis for each subject pollutant.

5.2.1 Particulate Matter (PM, PM_{10}, $PM_{2.5}$)

Particulate matter emissions, including PM, PM_{10}, and $PM_{2.5}$, occur from the combustion of coal, as fuel. Particulate is formed within the boilers during the combustion process and is present as unburned carbon, fly ash, and bottom ash. Fly ash and bottom ash are combustion by-products that are either placed in a landfill or sent offsite for beneficial reuse, generally for Portland cement manufacturing or in the road construction industry. Fly ash is a fine powder that exits the boiler with the flue gas stream and is captured in the particulate control device. Bottom ash consists of larger, agglomerated particles that are too large to exit with the flue gas stream and fall to the bottom of the boiler bed. The bottom ash is then cooled and is periodically emptied via hopper or submerged chain conveyor.

Particulate matter (PM) may be emitted as a solid, or it can be emitted as a condensable material. Solid particulate is measured using EPA's Method 5 sampling procedure and is commonly referred to as "front half" emissions. The condensable particulate emissions are measured using EPA's Method 202 procedure, and are commonly referred to as "back half" emissions. The filterable particulate, "front half", emissions are easily captured in the particulate control device and consist of carbonaceous materials, silica, and various trace quantities of metals found in the coal feedstock.

Condensable particulate matter consists primarily of inorganic compounds, typically nitrogen compounds and sulfur compounds that exist in the vapor form at the high temperatures of a utility boiler flue gas stream but will condense, or nucleate, into particles when cooled to below 20°C (68°F). Method 202 is used to measure the condensable fraction of PM from a coal-fired utility boiler. It uses impingers to capture and cool condensable particulate from the emissions stream. This method can be problematic in that secondary particulate can form in the measurement process resulting in an overstatement of the regulated particulate matter. Examples include oxidation of SO_2 to SO_3 in the impinger, ammonia slip reactions in the impinger to produce ammonium bisulfate ($NH_3 \rightarrow NH_4HSO_4$) and absorption of soluble NO_x components[1]. To address these problems, the USEPA has established a workgroup and is performing studies to address the inherent problem of artifact formation with Method 202 (i.e., the measurement of sulfates in the impinger solution as a result of chemical reactions). In the meantime, permits are being written to allow adjustments to Method 202 to allow more accurate measurement of condensable particulate matter.

5.2.1.1 Possible Control Technologies

Currently accepted control technologies for filterable particulate matter include fabric filters (baghouse) and electrostatic precipitators (ESP). The fabric filter and ESP technologies represent efficient and cost-effective methods for controlling PM emissions from utility boilers. While other

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[1] *Particulate Emissions – Combustion Source Emissions Dependent of Test Method*, Andracsek and Gaige, Burns & McDonnell.

control technologies exist, including mechanical collectors and wet scrubbers, neither has been proven to be an effective control technology due to efficiency and energy impacts and are used only as pre-cleaners to remove larger particles leaving the boiler.

Fabric Filter (baghouse)

A fabric filter system consists of a structure containing fabric bags arranged in numerous rows whereby the exhaust flue gas passes through the bags and filterable particulate matter is captured in the flue gas stream prior to exiting to an exhaust stack. Particles are "removed", or filtered, from the exhaust gas by various mechanisms, including inertial impaction and impingement, as the gas passes through the fabric bags. The accumulated particles ("dust cake") are periodically removed from the bags using either mechanical or pneumatic means.

Fabric filters achieve high removal efficiencies by designing the system with an air-to-cloth ratio that ensures the exhaust gas velocity through the bags is low enough to allow the dust to accumulate on the surface of the bag. This build up of dust on the surface effectively increases the removal efficiency of the bags by decreasing the sieve size of the filter media (bags). Typical collection efficiencies for a fabric filter system are on the order of 99.9 percent for particles down to 10-microns in size.

Fabric filters are typically installed in three basic designs referring to how the filter cake is removed from the filter media: pulse jet, mechanical shaker, and reverse air. With pulse jet fabric filters, as a filter cake forms on the outside of the bags, a pulse of air is blown vertically down the inside of the bags to dislodge the filter cake, which falls into a hopper for collection. In mechanical shaker fabric filters, the bags are mechanically shaken to remove the accumulated filter cake. In reverse air units, the flow is reversed to remove the built-up particulate.

Electrostatic Precipitators (ESP)

Electrostatic precipitators (ESP) remove particles from a gas stream through the use of electrical currents and forces. Dust laden gases are pushed or pulled through the precipitator box with the assistance of a fan. The airflow is channeled into lanes formed by collection plates. Discharge electrodes are centered between each collection plate to provide a negative charge to the surrounding dust particles. The collection plates are positively grounded and attract the negatively charged dust particles. The collected dust is transported down the collection plates and electrodes into a collection hopper with the assistance of a rapper or vibrator system.

Electrostatic precipitation for a power plant is typically a dry process. Where condensable organic emissions are significant, such as in the wood products industry, wet ESP's are used to reduce VOC and condensable particulate emissions in addition to the filterable PM emissions. In wet ESP technology, water is sprayed into the incoming air stream to reduce the resistivity of the particulate and increase the removal efficiency. The flow of water by gravity down the plate continually removes the collected contaminants. Since the contaminants are part of a liquid matrix, water treatment facilities must also be included as part of the overall control system for a wet ESP. Wet ESPs are discussed further for control of H_2SO_4 emissions in Section 5.2.6.

5.2.1.2 Eliminate Technically Infeasible Options

Both fabric filters and ESPs are considered technically feasible options and effective at controlling filterable emissions of particulates. Consumers has not considered either mechanical collectors or wet scrubbers as a primary control device for PM since neither has been demonstrated to achieve the removal efficiencies of fabric filters and ESPs. Typically, mechanical collectors are used with circulating fluidized bed boilers and stoker boilers in various industries to remove large particulates from the flue gas. These are often used for boilers firing wood and wood waste as fuel. Application of wet ESP technology is generally not used as the primary particulate control device with coal combustion boilers. Instead, as mentioned previously, wet ESPs are used in applications that produce a high amount of organic compounds, including VOC and condensable particulate.

5.2.1.3 Ranking of Technically Feasible Options

Dry ESPs have been proven effective at controlling filterable PM, with removal efficiencies typically between 99.0 and 99.5%. Fabric filters have been proven to be very effective at removing filterable PM, including PM_{10} and $PM_{2.5}$. Removal efficiencies for newer equipment are consistently proven to be 99.9%. When considering the installation of sorbent injection for mercury control and hydrated lime injection for SO_3 control, and the increase in particulate loading to the control device, use of fabric filters has become the primary particulate control device in most new boiler installation projects especially those where high sulfur content coal will not be burned. In addition, fabric filters remove the particle bound trace metals known to exist in fly ash, including mercury and lead better than ESPs. Therefore, use of a fabric filter is considered superior to a dry ESP for this project. In fact, as referenced by USEPA in their statement of basis for the Deseret Power Electric Power Cooperative, recent studies conducted on behalf of USEPA and the DOE suggest that fabric filters achieve a much higher mercury removal when compared to ESPs. The report suggests that fabric filters can achieve 70% control while ESPs achieve only 9%.

Table 5-1. Ranking of PM/PM$_{10}$ Control Technologies

Control Technology	Control Efficiency (%)
Fabric Filter	99.0 – 99.9
Dry ESP	99.0 – 99.5

NOTE: The proposed PM emission limit of 0.011 lb/MMBtu has been established through the case-by case-MACT included in Appendix J. Updated emission estimates are provided in the January 2009 revisions to Section 3.

5.2.1.4 Proposed BACT Emission Limit

The proposed BACT particulate limit based on this top-down analysis is a filterable particulate (PM and PM$_{10}$) emission limit of 0.012 lb/MMBtu heat input based on a rolling 24-hour average, which is lower than the NSPS limit of 0.015 lb/MMBtu for filterable particulate (PM only). This proposed BACT limit will be achieved by utilizing a new fabric filter to control total particulate emissions from the combustion of the proposed coals. The proposed limit for total PM$_{10}$ (filterable and condensable) is 0.025 lb/MMBtu based on a 24-hour average. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize particulate and these emissions will be included as part of the total annual emissions of 430.5 tpy. Table 5-2 provides a summary of recently issued and proposed BACT limits for PM/PM$_{10}$ for comparison purposes.

MDEQ has historically required a total particulate emission limit (as total PM$_{10}$) for permits that includes both “front-half” (filterable) and “back-half” (condensable) particulate emissions with compliance demonstrated by the use of a Method 5 + Method 202 sampling train. As mentioned previously, condensable particulate matter consists primarily of inorganic compounds, typically nitrogen compounds and sulfur compounds that exist in the vapor form at the high temperatures of a utility boiler flue gas stream but will condense, or nucleate, into particles when cooled below

20°C. Consumers will be utilizing a selective catalytic reduction system for the control of NO_x emissions. This system will use ammonia as the reagent to convert NO and NO_2 to H_2O and N_2. While Consumers will monitor closely the amount of ammonia injected into the flue gas stream, any un-reacted reagent ("ammonia slip") would increase the measured condensable particulate emissions.

Because of the known problems with Method 202 and variability in condensable particulate emissions, Consumers proposes a total particulate (as PM_{10}) limit of 0.025 lb/MMBtu. Consumers also proposes to work with MDEQ to establish appropriate adjustments to Method 202 to reflect the latest science on detection and quantification, which is rapidly developing under EPA supervision. This limit is consistent with the BACT limits established for several other similar sized PC boilers utilizing a blend of both sub-bituminous and bituminous coals.

Table 5-2. Summary of PM/PM_{10} BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.035 total	2-hour	Fabric Filter
LS Power White Pines	NV	1,590	DRAFT	0.05 total	3-hour	Fabric Filter
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.018 total	6-hour	FF or ESP
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.02 total	3-hour	Fabric Filter
TXU Oakgrove 1&2	TX	1,600	DRAFT	0.04 total	1-hour	Fabric Filter
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.013 filterable		Fabric Filter
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.025 total	1-hour	Fabric Filter
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	0.015 filterable	3-hour	Fabric Filter
American Municipal Power Ohio Generating Station	OH	1,960	DRAFT	0.025 total	3-hour	Fabric Filter
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.02 total	3-hour	Fabric Filter
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	0.02 total	24-hour	Fabric Filter
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.018 total	3-hour	Fabric Filter
LS Power Longleaf	GA	1,200	2007	0.03 total	3-hour	Fabric Filter

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Duke Power Cliffside Unit 6	NC	800	2007	0.018 total	1-hour	Dry ESP Wet ESP
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	0.02 total	24-hour	Fabric Filter
City of Springfield Dallman Unit 4	IL	2,440	2006	0.035	3-hour block	Fabric Filter
LS Power Sandy Creek	TX	800	2006	0.015 filterable 0.040 total	Annual Annual	Fabric Filter
Omaha Public Power District Nebraska City 2	NE	660	2005	0.018 total	3-hour	Fabric Filter
Louisiana Generating, LLC Trimble County Generating Station	KY	750	2005	0.015 filterable 0.018 total	3-hour	Fabric Filter
City Public Service Spruce 2	TX	750	2005	0.033 0.022	1-hour Annual	Fabric Filter
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.0236	30-day	Fabric Filter
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.035 total	3-hour block	Dry ESP
Santee Cooper Cross Units 3&4	SC	1,220	2004	0.018 total	1-hour	Dry ESP Wet ESP
Intermountain Power IPP 3	UT	950	2004	0.012 filterable	1-hour	Fabric Filter
Longview Power, LLC Longview Power	WV	600	2004	0.018 total	6-hour	Fabric Filter
MidAmerican Energy Council Bluffs	IA	750	2003	0.025 total	3-hour	Fabric Filter
LS Power Plum Point	AR	800	2003	0.018 total	3-hour	Fabric Filter
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.018 total	1-hour	Fabric Filter
Mid-American Energy Council Bluffs – Unit 4	IA	790	2003	0.025 total	3-hour	Fabric Filter
Tucson Electric Springerville 3/4	AZ	800	2002	0.015 filterable 0.055 total		Fabric Filter Dry ESP

5.2.2 Sulfur Dioxide (SO_2)

SO_2 is emitted as a result of the presence of sulfur in the fuel being combusted. Typically, sulfur is present in fuels, including natural gas, wood, coal, lignite, waste materials, etc., but in varying degrees. As an example, pipeline natural gas and wood typically have trace amounts of sulfur present. Similarly, some ranks of coal are lower in sulfur content than others. Western sub-bituminous coals typically have sulfur contents less than 0.5% while Eastern bituminous coals have been known to have sulfur contents higher than 3%. Variations within coal ranks also exist with some bituminous coals having sulfur concentrations of less than 1%.

During the combustion process, the sulfur present in the fuel is oxidized during the combustion process and combines with oxygen in the combustion air to form sulfur oxides. The sulfur oxides are primarily SO_2, with lesser amounts of SO_3.

5.2.2.1 Possible Control Technologies

PC Boilers that are required to control SO_2 emissions will do so using one of three primary methods. These methods consist of either dry, semi-dry or wet flue gas desulfurization (FGD). A further subcategory of each is either once-through or regenerable FGD systems. In wet FGD systems, an alkaline slurry of lime or limestone is sprayed into the flue gas as it passes through an absorber tower. All wet FGD systems are considered post-combustion FGD systems. In dry or semi-dry FGD systems, an alkaline sorbent (usually lime) is sprayed onto the flue gas as it passes through a spray dryer vessel or limestone can be added directly into the boiler in the case CFB technology. A fourth technology that is sometimes used to comply with sulfur in fuel limits is coal washing. This technique is used to remove pyretic sulfur from the coal to lower the sulfur content of the coal.

Once-through technologies are those systems where the SO_2 is permanently bound to the alkaline sorbent and is disposed of as a waste or saleable product (gypsum). In regenerable FGD systems, the spent sorbent is further processed to yield sulfuric acid, elemental sulfur, or liquid SO_2. Due to market conditions for sulfuric acid, elemental sulfur, and liquid SO_2, regenerable FGD systems are not being considered, as the extra cost to process the waste byproduct will not yield a favorable return. Therefore, only once-through technologies are addressed in the following sections.

Dry Flue Gas Desulfurization

In dry FGD systems, SO_2 reacts with the calcium- or sodium-based reagent to form $CaSO_3$ (calcium sulfite), $CaSO_4$ (calcium sulfate), Na_2SO_3 (sodium sulfite), or Na_2SO_4 (sodium sulfate). The dry reagent is injected into the flue gas stream and the solids are then removed in either the fabric filter or ESP device. SO_2 emissions control using a dry FGD system prior to a PM control device consists of spray nozzles where a certain amount of powdered sorbent (e.g., lime-based or sodium-based reagent) is injected either directly into the furnace, the economizer or into the flue gas stream downstream of the economizer outlet. Typical control efficiencies for new dry FGD systems are on the order of 50 to 80%.

Dry FGD systems consist of either post-combustion desulfurization or injection of limestone into the bed of a boiler that utilizes either bubbling or fluidized bed technology where combustion is on-going. A more detailed description of the post-combustion control technologies is provided in the following paragraphs.

Trona

Trona is a naturally occurring mineral primarily mined in California, Utah, and Wyoming, and is known chemically as sodium sesquicarbonate ($Na_3HCO_3CO_3 \bullet 2H_2O$). It has been used on a limited basis to remove SO_x, HCl, and HF from exhaust gas streams. While Trona was discovered nearly 20 years ago and has been used experimentally at some facilities for SO_2 removal, it has limited commercial application. Further, removal efficiencies vary widely, are dependent on flue gas temperature, and have been generally found to be less than 70% on a consistent basis.

Semi-Dry Flue Gas Desulfurization

In semi-dry systems, an aqueous solution of slaked lime (or lime slurry) is injected into the flue gas stream downstream of the economizer outlet. The water then evaporates due to the temperature of flue gas.

In general, both dry and semi-dry FGD systems for use with pulverized coal boilers utilize lime as the alkali to react with SO_2. The primary reactions in the spray dryer absorber occur when combining sulfur dioxide with slaked lime (calcium hydroxide) to produce calcium sulfite, calcium sulfate and water. Typical removal efficiencies for semi-dry FGD systems are slightly less than for wet FGD systems and on the order of 90 to 92%. The chemical reactions can be shown as:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet ½H_2O + ½H_20$$

$$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

$$CaSO_3 + ½O_2 \rightarrow CaSO_4$$

Lime Spray Drying

Lime spray drying (LSD) consists of either an atomized slurry of lime or hydrated lime that is sprayed into the flue gas inside of the spray dryer absorber and upstream of the particulate control device. In LSD processes, use of either dry lime, slaked lime (calcium hydroxide), or sodium bicarbonate to react with both SO_2 and SO_3 is accomplished either in-situ within the duct stream exiting the economizer or within a spray dryer. The water content is carefully monitored to ensure that complete saturation of the flue gas is avoided. Complete saturation of the flue gas ultimately leads to problems within the spray dryer and plugging of fabric filters.

Wet Flue Gas Desulfurization

The wet scrubber FGD process uses a saturated method for controlling SO_2. This type of control is typically located downstream of the PM control device such that the saturated exhaust gas does not interfere with the effectiveness of the PM control device (e.g., such as the fabric filter proposed for the ASCPC boiler). Wet FGDs typically use a spray tower wherein the flue gas passes vertically upward through the tower while limestone slurry is sprayed downward to react with the SO_2 in the flue gas stream. Typical reagent is limestone and wet FGD systems using limestone have demonstrated control efficiencies of 95 to 98%. Lime is a more expensive material and typically results in lower removal efficiencies.

In a wet FGD system, the SO_2 reacts with the hydrated calcium oxide (lime or limestone) and produces primarily calcium sulfite with some calcium sulfate, which are both commonly referred to as gypsum. The resulting gypsum then can be sold or recycled to produce wallboard for the construction industry or used as an additive in the manufacture of Portland cement if the commercial market exists. Wet FGD control systems typically result in 95% – 98% control of the potential SO_2 emissions, depending on the inlet concentration of SO_2 in the flue gas entering the absorber, and ratio of slurry to SO_2, referred to as the liquid-to-gas ratio (L/G).

Wet FGD systems generally include three primary designs: calcium-based, sodium-based, or dual-alkali. In a calcium-based system, lime or limestone slurry is sprayed through the tower, as mentioned previously. A newer calcium-based process called limestone forced oxidation (LSFO) blows air into the reaction tank to oxidize the spent slurry into gypsum. In sodium-based systems, sodium carbonate is used as the reagent solution. Due to the higher reactivity within this system, L/G ratios are usually much lower. In dual-alkali systems, both calcium- and sodium-based solutions are used to control SO_2 emissions. A sodium-based solution is used to remove SO_2 while a calcium-based solution is used to regenerate the sodium-based solution. This process also requires a lower L/G ratio than with typical calcium-based systems and additional sludge processing is required with a resultant loss of saleable gypsum.

In general, the chemical reaction occurring in a wet FGD system is to react SO_2 with calcium carbonate to yield water, carbon dioxide, calcium sulfite and calcium sulfate (collectively known as gypsum). The general reaction is as follows:

$$SO_2 + CaCO_3 + ½H_20 \rightarrow CaSO_3•½H_20 + CO_2$$

$$SO_2 + ½O_2 + CaCO_3 + 2H_20 \rightarrow CaSO_4•2H_20 + CO_2$$

Limestone Forced Oxidation (LSFO)

The natural byproduct of wet FGD systems is calcium sulfate (gypsum). Gypsum is formed as a result of oxidation of the reaction byproducts. Historically, oxidation and gypsum formation within the absorber, mist eliminator and other equipment would cause scaling problems resulting in operational problems with the wet FGD system.

To prevent oxidation within system, air is blown into the absorbent slurry to encourage controlled oxidation outside of the absorber. This is known as limestone forced oxidation (LSFO) and is now the preferred system for most wet FGD processes. The LSFO process has consistently proven to provide greater reliability and control of SO_2 and SO_3 emissions. Reductions of SO_2 emissions from LSFO systems are typically 95% to 98% for boilers similar in size to the proposed ASCPC.

Limestone Inhibited Oxidation (LSIO)

Similar to LSFO, limestone inhibited oxidation (LSIO) wet FGD systems were designed to control oxidation within the absorber. In a LSIO system, emulsified sodium thiosulfate ($Na_2S_2O_3$) or sulfur is added to the limestone slurry to prevent oxidation inside the absorber. This is accomplished by lowering the amount of calcium sulfate to less than 15%.

Magnesium Enhanced Lime (MEL)

Magnesium Enhanced Lime (MEL) is a wet FGD process whereby slaked lime containing calcium hydroxide and magnesium hydroxide is used to react with SO_2. MEL is simply a wet FGD process that uses treated lime slurry for increased SO_2 removal. Typical removal efficiencies for a MEL wet FGD are 95%-98% for boilers burning primarily higher sulfur coals. In the MEL process, magnesium hydroxide ($Mg[OH]_2$) reacts with SO_3 and SO_2 to form magnesium salts and sulfite compounds that can be easily removed and handled. In general, the decision to use MEL over other traditional wet FGD systems is site-specific and can be more costly when compared to limestone costs depending on location.

Dual Alkali

In dual-alkali wet FGD systems, both calcium and sodium are used in the reaction process. The sodium slurry is typically sodium hydroxide (Na_2OH) used for SO_2 removal and absorption while calcium slurry is used to regenerate the spent sodium liquor. The dual-alkali process requires lower L/G ratios and uses less water. However, dual-alkali systems are typically used on units much smaller than the proposed 930 MW ASCPC boiler for this project.

Coal Washing

Coal washing is a fuel cleaning process that is a process that is primarily used to remove pyretic sulfur from the coal through the use of a water bath. This process can also remove excess fines and rocks from coal, and can be used to enhance the burning characteristics as well. Coal washing is typically a wet process whereby the coal is floated in a bath of water that allows the heavier inorganic pyrite to sink. By varying the density of the water bath with various dissolved salts, a greater or lesser degree of washing is accomplished through density separation. Therefore, the washing is accomplished through separation by means of gravity. However, the coal can be “washed” by dry means that crushes and screens the coal to remove impurities.

Wet coal washing produces a large amount of coal waste and slurry, which can pose risk of environmental impact. The washing process also requires energy and can result in adverse energy impacts. Coal washing is not a technically feasible option for low sulfur sub-bituminous coals, including the PRB coals that Consumers will be purchasing. Further, coal washing is a redundant technology when including flue gas desulfurization add-on control devices.

Multi-Pollutant Control Technologies

Certain multi-pollutant control technologies have undergone pilot studies and testing to determine their feasibility for commercial. In general, most, if not all, multi-pollutant control technologies target existing units for retrofit in order to obtain the necessary reductions to comply with newly promulgated regulations given current site configurations and restraints.

Electro-Catalytic Oxidation

Electro-Catalytic Oxidation (ECO) is a proprietary technology developed by Powerspan Corp. for reducing emissions of $PM_{2.5}$, NO_x, SO_2, and certain toxic air contaminants. The ECO process treats flue gas exiting a coal-fired boiler in three steps. In the first step, most of the fly ash is removed from the flue gas with a conventional dry ESP. Once the flue gas passes through the ESP, the flue gas passes through a barrier discharge reactor that oxidizes the gaseous pollutants to higher oxides. The oxidized gaseous pollutants are then captured downstream in a wet ESP that removes additional ash as well.

The liquid effluent from the wet ESP can be treated to remove collected ash and sent to a distillation system for processing to produce concentrated sulfuric and nitric acids, if desired. However, this distillation process is not a necessary component of the ECO system.

To date, the ECO system has only undergone pilot testing at the FirstEnergy R.E. Burger Plant in Shadyside, OH as part of a 50 MW unit. This pilot program began in May 1999 and continued through September 1999 with testing of the multi-tube dielectric barrier discharge. During this initial testing, which lasted for 9-hours, NO_x removal efficiencies of 74.5% and SO_2 removal efficiencies of 43.8% were recorded. While the ECO system subsequently underwent a 180-day demonstration project that was completed in September 2005, data regarding the control of NOx and SO2 has not been published. Only the 1999 data has been published in which Powerspan states that this data is considered representative of the ECO pilot unit performance.

5.2.2.2 Eliminate Technically Infeasible Options

Both dry and wet FGD systems are considered technically feasible options and effective at controlling emissions of sulfur dioxide and acid gases. Consumers has not considered direct limestone injection into the furnace as this is technically not feasible, since it would cause significant problems in flame-out due to mixing of limestone with coal in the pulverizers and the potential for voids in fuel through the spray nozzles. Typically, such an approach is used with fluidized bed boilers and stoker boilers in various industries. Since Consumers will not be utilizing fluidized bed technology, direct limestone injection into the combustion chamber is not feasible.

Trona has only been used on a limited basis throughout the U.S. in the past several years. Currently, very few companies commercially offer such a system for SO_2 removal from large utility boilers. While Trona has been shown to provide multi-pollutant control, such as SO_2, SO_3, and acid gases, the removal efficiencies of SO_2 and SO_3 are significantly lower than typical dry FGD systems using lime injection.

Inhibited oxidation technologies, including LSIO, have not been used in the industry in over 15 years and pose problems by eliminating the production of gypsum, a useful by-product. Further, LSIO is not commercially available from vendors since other (LSFO) technologies offer superior control at lower costs. For these reasons, LSIO has been eliminated as a technically feasible option. Further, LSIO wet FGD systems perform best on units burning high sulfur coals, specifically bituminous coals.

While both the sodium-based and dual-alkali-based wet FGD are considered technically infeasible for the proposed ASCPC, they can be considered inferior technologies to the calcium-based systems since removal efficiencies are often lower and costs significantly higher. Further, the calcium- and sodium-based systems are no longer offered. Therefore, neither of these technologies has been considered further in the BACT analysis.

Coal washing is a technically feasible option for high sulfur bituminous coals but not for low sulfur western sub-bituminous coals. Typically, coal washing is done in order to meet the fuel specifications required by the purchaser for use in their boiler design. However, typical sulfur removals resulting from this process are on the order 20 – 25%. This is much lower than the 96+% removal efficiencies routinely seen from other FGD systems. Table 5-3 provides a ranking of the available control technologies.

The ECO process has only been demonstrated during pilot testing at one facility for a unit that is significantly smaller than the proposed ASCPC. Therefore, ECO has been eliminated as a technically feasible option since it has not been proven commercially on units greater than 50 MW in size and has produced removal efficiencies lower than the pollutant-specific add-on controls.

5.2.2.3 Ranking of Technically Feasible Options

Dry, wet, and magnesium enhanced lime wet FGD systems have been proven effective at controlling SO_2 and SO_3 with removal efficiencies typically between 90 and 98%. In general, wet FGD systems are more efficient and have slightly higher removal efficiencies when compared to dry FGD systems. This is due to the lower reactivity and lower L/G ratios of the dry and semi-dry systems. However, wet FGD systems are known to have higher operating costs than dry systems due to the need to treat wastewater and gypsum by product.

Typically, dry FGD systems are installed on units that burn only low sulfur coals, primarily sub-bituminous. While the proposed ASCPC unit is designed to burn PRB and other sub-bituminous coals, the unit will have the ability to use a blend of both sub-bituminous and bituminous coals while still meeting the target inlet SO_2 emission rate. Consequently, a dry FGD system is not expected to deliver the same level of control as a wet FGD system using limestone. Additionally, a wet system will provide additional benefits in controlling acid gases and provide some minor additional particulate removal.

Since the proposed ASCPC boiler will have the ability to burn a blend containing higher sulfur Eastern bituminous coals, the performance of a dry FGD system will not match the ability of a wet system to reduce SO_2 emissions. Similarly, Trona and coal washing are inferior to the wet FGE. Table 5-3 provides a ranking of the available flue gas desulfurization processes.

Table 5-3. Ranking of SO_2 Control Technologies

Control Technology	Control Efficiency (%)
Wet FGD (including MEL)	95.0 – 98.0
Dry FGD	90.0 – 95.0
Coal Washing	20 – 25%

5.2.2.4 Proposed BACT Emission Limit

The proposed BACT SO_2 limit based on this top-down analysis is 0.06 lb/MMBtu, based on a 30-day rolling average. Consumers proposes to install a new LSFO wet FGD system to control SO_2 emissions from the combustion of the proposed coals to achieve this BACT limit. The wet LSFO will provide the same level of control as the MEL wet FGD and so no economic analysis is provided. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize SO_2 and these emissions will be included as part of the total annual emissions of 2,152.3 tpy. Table 5-4 provides a summary listing of recent BACT determinations and permit levels for similar pulverized coal units.

EPA has promulgated a NSPS for electric utility steam generating units codified at 40 CFR Part 60 Subpart Da. This standard was recently revised on February 27, 2006 and sets emission limits for PM, SO_2, NO_x, and Hg. The LSFO wet FGD to be installed as part of the overall project will be designed to achieve a SO_2 emission limit of 0.06 lb/MMBtu heat input (0.55 lb/MWh), which is lower than the NSPS limit of 1.4 lb/MWh for SO_2 and provides a reduction of at least 95% in uncontrolled SO_2 emissions when burning only sub-bituminous ranks of coal and greater than 95% reduction in uncontrolled emissions when blending sub-bituminous coals with higher sulfur bituminous coals. This level of emissions is considered the BACT limit for this process and is significantly lower than the limit established in the recently revised NSPS.

Table 5-4. Summary of SO_2 BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.095	30-day rolling	Dry FGD
LS Power White Pines	NV	1,590	DRAFT	0.09 > 0.45% 0.065 < 0.45%	24-hour rolling 24-hour rolling	Dry FGD
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.15	30-day rolling	Wet FGD
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.10 0.09	30-day rolling 12-month rolling	Wet FGD
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.04		Wet FGD
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.04 0.055	30-day rolling 24-hour block	Wet FGD
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	NA	NA	NA
American Municipal Power Ohio Generating Station	OH	960	DRAFT	0.18 0.15	24-hour 30-day rolling	Wet FGD
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.06	24-hour	Wet FGD
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	0.06	24-hour rolling	Wet FGD
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.15	30-day rolling	Wet FGD
LS Power Longleaf	GA	1,200	2007	0.065 < 1 0.08 > 1	30-day rolling 30 day rolling	Dry FGD
Duke Power Cliffside Unit 6	NC	800	2007	NA	NA	Wet FGD
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	0.065	30-day rolling	Wet FGD
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	0.060	24-hour	Wet FGD Hydrated Lime
City of Springfield Dallman Unit 4	IL	2,440	2006	NA	NA	NA
LS Power Sandy Creek	TX	800	2006	0.30 0.12	1-hour 30-day rolling	Dry FGD
Omaha Public Power District Nebraska City 2	NE	660	2005	0.095 0.263	30-day rolling 24-hour rolling	Dry FGD
Louisiana Generating, LLC Trimble County Generating Station	LA	750	2005	NA	NA	Wet FGD
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.09	30-day rolling	Wet FGD
TXU Oakgrove 1&2	TX	1,600	2005	0.192	30-day rolling	Wet FGD
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.182	30-day rolling	Wet FGD
City Public Service Spruce 2	TX	750	2005	0.36 0.10	1-hour 30-day rolling	Wet FGD
Black Hills Corporation Wygen Station I	WY	80	2005	0.20 0.17	3-hour block 30-day rolling	Dry FGD

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Santee Cooper Cross Units 3&4	SC	1,220	2004	NA	NA	Wet FGD
Intermountain Power IPP 3	UT	950	2004	0.10 0.09	24-hour block 30-day rolling	Wet FGD
Longview Power, LLC Longview Power	WV	600	2004	0.15 0.12	3-hour rolling 24-hour rolling	Wet FGD
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.1	30-day rolling	Dry FGD
LS Power Plum Point	AR	800	2003	0.16	3-hour CEMS	Dry FGD
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.167 0.41	30-day rolling 24-hour block	Wet FGD
Intermountain Power IPP 1 & 2	UT	2,100	2003	0.138	30-day rolling	Dry FGD

5.2.3 Nitrogen Oxides (NO_x)

NO_x is emitted as a result of nitrogen in the fuel being oxidized (referred to as fuel NO_x) and due to disassociation of diatomic nitrogen and subsequent combining with oxygen in the combustion air at the high temperatures of the combustion zone (referred to as thermal NO_x). The nitrogen oxides are primarily emitted as nitrogen oxide (NO). Within the combustion zone of a boiler, the primary formation of NO_x is governed by the Zeldovich equations as follows:

$$N_2 + O \rightarrow NO + N$$

$$N + O_2 \rightarrow NO + O$$

$$N + OH \rightarrow NO + H$$

NO_x is controlled by using several techniques; either alone, or in conjunction with both internal and external technologies. New boilers implement modern state-of-the-art combustion techniques that minimize both flame temperature and excess air in the combustion zone. Add-on control techniques include the use of injecting ammonia or urea into the exhaust gases at the correct exhaust gas temperature, which is known as selective non-catalytic reduction (SNCR). Technology has also been developed to include a catalyst bed downstream of an ammonia/urea injection system that further reduces NO_x from the exhaust gas stream. This is known as selective catalytic reduction (SCR).

5.2.3.1 Possible Control Technologies

Control options for NO_x consist primarily of two techniques: combustion modification and post-combustion control, or a combination of both. With combustion modifications, the burner and/or furnace box are designed to control peak flame temperature and air-to-fuel ratio and thereby minimize NO_x formation. Post combustion controls consist of installation of add-on control technologies to reduce NO_x emissions through chemical reactions by converting NO_x to nitrogen and water.

Combustion Controls

As mentioned previously, combustion controls attempt to reduce the formation of thermal NO_x inside the boiler by controlling the conditions in the combustion zone. Typical combustion controls consist of:

1. Low NO_x Burners (LNB)
2. Overfire Air (OFA)
3. Reburning
4. Flue Gas Recirculation (FGR)

Low NO_x Burners (LNB)

Low NO_x Burners (LNBs) are designed to control the mixing of fuel and air to achieve staged combustion within the boiler. Staged combustion reduces both flame temperature and oxygen concentration, resulting in cooler peak flame temperatures, reduced oxygen and reduced residence time at peak flame temperature. All of these lead primarily to reductions in thermal NO_x and, to a lesser extent, fuel NO_x production.

LNBs have been widely used in all sizes of boilers, including utility boilers, and are typically installed in any new boiler design. In general, NO_x reductions of 20% - 50% can be achieved through the installation of LNBs alone. However, most new utility boiler systems use LNBs in conjunction with other combustion control techniques and post-combustion controls to achieve the maximum level of control necessary.

Overfire Air (OFA)

Overfire air (OFA) is another combustion technique in which the flame temperature and oxygen are controlled through staged combustion. Air is injected into the furnace above the primary combustion zone causing the primary combustion chamber to operate in a fuel-rich mode. In other words, the primary combustion chamber is operated at a low air-to-fuel ratio (i.e., rich burn). As with LNBs, OFA minimizes the formation of thermal NO_x.

Typically, modern boilers are constructed with both LNB and OFA technologies to minimize the formation of thermal NO_x exiting the boiler. In general, thermal NO_x reductions of up to 30% can be obtained through the use of OFA.

Reburning

Reburn is a combustion process where a portion of the fuel (typically 10-25%) is re-directed outside of the primary combustion chamber and added in a secondary, oxygen-limited environment. Such a fuel-rich combustion zone limits the amount thermal NO_x that can be formed but also limits fuel NO_x in the primary combustion chamber. Typically, reburn is used with OFA injected above the secondary combustion chamber (reburn zone) to encourage complete combustion of fuel.

Reburn has three (3) combustion zones within the boiler: 1) primary combustion zone; 2) reburn (secondary) combustion zone; and 3) burnout zone. In the primary combustion zone, fuel is combusted under near normal stoichiometric conditions. In the reburn zone, fuel is combusted in an oxygen-limited environment leading to a fuel-rich situation. In the burnout zone, OFA is added to complete combustion.

Reburn has shown to reduce total NO_x formation by up to 50% in certain circumstances and is generally found to reduce thermal NO_x by 30%.

Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is a simple process that re-directs a portion of the flue gas exiting the boiler back into the boiler combustion zone. FGR works to lower the flame temperature and increase the fuel-to-air ratio, thereby reducing available oxygen and leading a rich-burn situation. This ultimately leads to reductions in both thermal and fuel NO_x formation within the boiler combustion zones.

FGR has been used successfully with liquid- and gas-fired boilers, and circulating fluidized bed boilers but has not been widely demonstrated as a practical application in pulverized coal-fired boilers due to the recirculation of fly ash back into the boiler. In addition, FGR is primarily used to minimize production of thermal NO_x, not fuel NO_x. As noted in Section 1.1.3.3 of the USEPA AP-42 document, coal-fired boilers have a significant portion of the total NO_x formed from fuel NO_x.

Post-Combustion Controls

Post-combustion controls are control devices that treat the flue gas directly after it exits the economizer where the flue gas temperature is highest. For boiler applications, there are two primary post-combustion control systems:

1. Selective Catalytic Reduction
2. Selective Non-Catalytic Reduction

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) is a process that reduces emissions of NO_x from the flue gas by reacting the NO_x with ammonia (NH_3) in the presence of a catalyst, usually a precious metal (platinum or rhodium) or metal oxides (titanium oxide or vanadium oxide). The chemical reaction that occurs acts to convert NO_x to nitrogen and water. The primary reactions are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Ammonia (NH_3) is injected into the flue gas stream exiting the economizer and requires a catalyst to react with the NO_x at the relatively low post-economizer flue gas temperatures. The NH_3 is injected into the flue gas stream at a controlled molar ratio (typically 1:1) based on the volume of flue gas, NO_x loading and temperature. The optimum operating temperature range for a SCR system is 600°F to 800°F. The catalyst acts to increase NO_x removal efficiency over a larger range of temperatures.

Problems associated with SCR technology includes catalyst fouling and ammonia slip. Since a catalyst is necessary to complete the reaction of NH_3 with NO_x, as the catalyst functionality declines, so does the overall NO_x removal efficiency. Therefore, the catalysts must be monitored and replaced as necessary. Injection of too much NH_3 results in ammonia slip that can cause high emissions of NH_3 and condensable particulates. Ammonia slip refers to NH_3 that does not react with the NO_x and is instead carried out of the SCR with the flue gas. To minimize this problem, it is desirable to hold NH_3 concentrations to below 10 ppm in the flue gas stream exiting the SCR.

NO_x removal efficiencies have been steadily increasing over the past 10 years as more and more companies have been installing these systems on existing units and vendors have been working to maximize the reaction rates by altering temperatures, catalysts, and flue gas volume. Removal efficiencies of 70-90% are common and can be achieved with a newly installed system.

Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is a process that reduces emissions of NO_x from the flue gas by reacting the NO_x with ammonia (aqueous or anhydrous) or urea inside the boiler. The chemical reaction that occurs acts to convert NO_x to nitrogen and water. The basic reactions are as follows:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + {}^{3}/_{2}H_2O \qquad \textit{In the case of } NH_3 \textit{ injection}$$

$$2NO_2 + (NH_2)_2CO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 2H_2O + CO_2 \qquad \textit{In the case of urea injection}$$

With SNCR, ammonia (NH_3) or urea is usually injected directly above the primary combustion zone, in the radiant and convection regions of the boiler. These regions serve as the reaction chamber where temperatures are 1,500°F and 2,100°F.

In general, SNCR systems are better suited for industrial processes that have emission stream temperatures that are outside the range of optimal SCR operation (i.e., processes that produce a high temperature flue gas stream, such as furnaces and kilns, or lower temperature operations such as circulating fluidized bed boilers). Further, NO_x removal efficiencies of SNCR systems are not as high as with SCR systems and tend to be limited to less than 50% without combustions controls, especially in situations where the concentration of NO_x is below 200 ppm. Thus, use of SNCR in new boiler applications that include state-of-the-art combustions is not an ideal application for this technology. However, SNCR systems in combination with combustion controls can deliver NO_x removal efficiencies of up to 75%.

Multi-Pollutant Control Technologies

Certain multi-pollutant control technologies have undergone pilot studies and testing to determine their feasibility for commercial. In general, most, if not all, multi-pollutant control technologies target existing units for retrofit in order to obtain the necessary reductions to comply with newly promulgated regulations given current site configurations and restraints.

Electro-Catalytic Oxidation

Electro-Catalytic Oxidation (ECO) is a proprietary technology developed by Powerspan Corp. for reducing emissions of $PM_{2.5}$, NO_x, SO_2, and certain toxic air contaminants. The ECO process treats flue gas exiting a coal-fired boiler in three steps. In the first step, most of the fly ash is removed from the flue gas with a conventional dry ESP. Once the flue gas passes through the ESP, the flue gas passes through a barrier discharge reactor that oxidizes the gaseous pollutants to higher oxides. The oxidized gaseous pollutants are then captured downstream in a wet ESP that removes additional ash as well.

The liquid effluent from the wet ESP can be treated to remove collected ash and sent to a distillation system for processing to produce concentrated sulfuric and nitric acids, if desired. However, this distillation process is not a necessary component of the ECO system.

To date, the ECO system has only undergone pilot testing at the FirstEnergy R.E. Burger Plant in Shadyside, OH as part of a 50 MW unit. This pilot program began in May 1999 and continued through September 1999 with testing of the multi-tube dielectric barrier discharge. During this initial testing, which lasted for 9-hours, NO_x removal efficiencies of 74.5% and SO_2 removal efficiencies of 43.8% were recorded. While the ECO system subsequently underwent a 180-day demonstration project that was completed in September 2005, data regarding the control of NOx and SO2 has not been published. Only the 1999 data has been published in which Powerspan states that this data is considered representative of the ECO pilot unit performance.

5.2.3.2 Eliminate Technically Infeasible Options

Both combustion controls and add-on control systems are considered technically feasible options and effective at controlling emissions of NO_x from a utility boiler. Consumers proposes to install a new advanced supercritical PC boiler at the existing Karn/Weadock complex. As the name implies, the boiler is expected to operate in supercritical mode and thermal efficiency is of paramount importance in order transfer as much heat to the boiler tubes to produce high-pressure steam for electricity generation. Because of the inherent loss in thermal efficiency associated with SNCR applications, use of this technology is infeasible for the new unit.

FGR is not a technically feasible option for this specific boiler due to problems associated with recirculation of fly ash back into the boiler combustion zone. The proposed ASCPC boiler is designed to combust sub-bituminous and bituminous coals. The boiler will not have the capability to operate on either natural gas, fuel oil, or other liquid or gaseous fuels.

Reburn is also not a technically feasible option since this technology is employed primarily on gas-fired boilers. Introducing reburn technology into a sold-fuel boiler poses problems with incomplete combustion of the solid fuel leading to higher concentration of coal dust and unburned carbon in the exiting flue gas.

The ECO process has only been used during pilot testing at one facility for a unit that is significantly smaller than the proposed ASCPC. Therefore, ECO has been eliminated as a technically feasible option since it has not been proven commercially on units greater than 50 MW in size and has produced removal efficiencies lower than the pollutant-specific add-on controls.

Therefore, the following technologies are considered to be technically infeasible for the proposed ASCPC boiler:

1. Selective Non-Catalytic Reduction (SNCR)

2. Flue Gas Recirculation (FGR)
3. Reburn
4. ECO Process

5.2.3.3 Ranking of Technically Feasible Options

Consumers will be designing the ASCPC boiler to minimize the formation of NO_x by utilizing combustion controls, including LNBs and OFA technology. Both of these technologies are readily available for new boiler installation and have proven very effective at limiting the formation of thermal NO_x. In addition, Consumers will be installing a SCR system at the outlet of the economizer to control emissions of both thermal and fuel NO_x within the flue gas. SCR has been determined to be the best performing post-combustion control system for NO_x control. In combination with LNB and OFA, SCR can reduce NO_x emissions up to 97% compared to uncontrolled emissions.

5.2.3.4 Proposed BACT Emission Limit

The proposed BACT NO_x limit based on this top-down analysis is 0.05 lb/MMBtu, based on a 30-day rolling average. Consumers proposes LNB, OFA and SCR technology to achieve this level of NO_x emissions from the combustion of the proposed coals. Through the use of LNB combustion controls, OFA, and SCR for post-combustion controls, NO_x removals of up to 95%, as compared to uncontrolled emissions, will be achieved. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize NO_x and these emissions will be included as part of the total annual emissions of 1,793.6 tpy. Table 5-5 provides a summary of recent BACT limits for new and proposed PC boilers

Table 5-5. Summary of NO_x BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.07	30-day rolling	SCR
LS Power White Pines	NV	1,590	DRAFT	0.07	24-hour	SCR
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.07	30-day rolling	SCR
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.07	30-day rolling	SCR
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.05		SCR
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.05 0.05	24-hour block 30-day rolling	SCR
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	NA	NA	SCR
American Municipal Power Ohio Generating Station	OH	960	DRAFT	0.1	30-day	SCR
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.06	24-hour	SCR
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	0.06	24-hour rolling	SCR
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.07	30-day rolling	SCR
LS Power Longleaf	GA	1,200	2007	0.07	30-day rolling	SCR
Duke Power Cliffside Unit 6	NC	800	2007	0.07		SCR
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	0.07 0.05	30-day Annual	SCR
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	408 0.06	3-hour 24-hour	SCR
City of Springfield Dallman Unit 4	IL	2,440	2006	NA	NA	NA
Omaha Public Power District Nebraska City 2	NE	660	2005	0.07	30-day rolling	SCR
Louisiana Gas & Electric Trimble County Generating Station	LA	750	2005	NA	NA	SCR
Louisiana Generating, LLC Big Cajun II	LA	675	2005	0.07		SCR
City Public Service Spruce 2	TX	750	2005	0.069 0.05	30-day rolling 12-month rolling	SCR
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.1	30-day rolling	SCR
TXU Oakgrove 1&2	TX	1,600	2005	0.07 0.05	30-day rolling 12-month rolling	SCR
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.07	30-day rolling	SCR

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Black Hills Corporation Wygen Station I	WY	80	2005	0.126	30-day rolling	SCR
Santee Cooper Cross Units 3&4	SC	1,220	2004	NA	NA	NA
Intermountain Power IPP 3	UT	950	2004	0.07	30-day rolling	SCR
Longview Power, LLC Longview Power	WV	600	2004	0.08	24-hour rolling	SCR
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.07	30-day rolling	SCR
LS Power Plum Point	AR	800	2003	0.09	30-day rolling	SCR
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.07	30-day rolling	SCR
Intermountain Power IPP 1 & 2	UT	2,100	2003			

5.2.4 Carbon Monoxide (CO)

Carbon monoxide is emitted from the ASCPC boiler as a result of incomplete combustion of the fuel. Factors affecting the formation of CO include the air-to-fuel ratio, combustion temperature, residence time, and turbulence (or mixing) of the combustion gases. In addition to the formation of CO, incomplete combustion also leads to increased emissions of particulate matter, including particulate, VOCs, and HAPs. Therefore, methods employed in order to reduce or control emissions of CO tend to reduce emissions of other pollutants as well.

5.2.4.1 Possible Control Technologies

There are three potential control technologies for controlling CO emissions from an ASCPC boiler: (1) catalytic oxidation, (2) thermal oxidation and, (3) efficient combustion. Catalytic oxidation is a post-combustion CO reduction technique that uses a catalyst to convert CO to CO_2. Thermal oxidation is post-combustion control technology that uses an afterburner to produce additional heat to convert the CO to CO_2 and water. Efficient combustion is a direct result of the design and operation of processes/process equipment.

Catalytic Oxidation

Catalytic oxidizers treat exhaust gas from a combustion device utilizing a catalyst bed, typically a media-supported film of precious metals, such as platinum/rhodium, where oxidation of CO to CO_2 takes place. Depending on catalyst formation, the reaction can occur over a temperature range of approximately 450°F to 1,200°F. The amount of CO oxidation (or conversion) will depend on several factors, including operating temperature, gas composition, and pressure drop across the catalyst bed.

Thermal Oxidation

Thermal oxidation employs the use of a thermal oxidizer (afterburner) to increase the temperature of the flue gas above the auto-ignition temperature of CO, 1,300°F, to induce combustion of flue gas contaminants (CO and VOC). There are two primary types of thermal oxidizers: regenerative and recuperative. In regenerative thermal oxidizers, packed bed media, such as ceramic filters, are used to preheat the flue gas stream. The exhaust gas is partially oxidized and used as fuel in the primary chamber. The partially oxidized flue gas then enters a combustion chamber to achieve final conversion of CO to CO_2. The combustion chamber is typically heated with auxiliary fuel, primarily natural gas. The hot exhaust stream exits the chamber and is directed to the ceramic-packed beds for heat transfer. Once thermal transfer is complete, the cooled exhaust gas exits the system. In recuperative systems, heat transfer is typically not as efficient and uses plate-to-plate and shell-and-tube heat exchangers to achieve thermal transfer. Otherwise, the oxidation principal is the same.

Efficient Combustion

Because CO emissions are a function of combustion operating conditions, the most direct approach for reducing these emissions is to maximize combustion efficiency. Maximizing combustion efficiency must be balanced with the potential increase of NO_x emissions that could occur when combustion efficiency is associated with high chamber temperatures. Modern combustion controls are able to balance this anomaly; i.e., reduce NO_x with a minimal resulting increase in CO (and VOC) emissions.

5.2.4.2 Eliminate Technically Infeasible Options

Catalytic oxidation is not a technically feasible option. To date, oxidation catalysts have not been used for coal-fired boilers. Coal firing has several serious technical problems related to the use of oxidation catalysts, including:

1. Catalyst fouling and poisoning by sulfur, flyash (including trace metals) and lime.
2. Low excess oxygen levels in the flue gas.
3. Low temperature levels of the flue gas.

Typically, vendors are not willing to offer catalytic oxidizers due to the issues stated above. Furthermore, catalytic oxidizers are nonselective and will oxidize other compounds. The presence of sulfur oxides will result in the formation of SO_3, which will in turn combine with moisture in the gas stream to form H_2SO_4 mist.

Lastly, the short catalyst life caused by fouling and poisoning would result in a significant and on-going generation of catalyst waste that would most likely be classified as a hazardous waste. For these reasons, and because oxidation catalysts have never been used or demonstrated in practice on coal-fired boilers, catalytic oxidation is not considered a technically feasible control option for CO for the proposed ASCPC boiler.

While thermal oxidation is theoretically possible, it is not a technically feasible BACT option. It has never been demonstrated for a coal-fired boiler. Thermal oxidation is primarily used with industrial processes where the flue gas is not produced as a result of combustion (i.e., paint booths and ovens). Industrial RTOs are typically designed for process streams that are less than 100,000 acfm, and have high concentrations of VOCs, where the contaminants provide a significant portion of the fuel requirements. Designing a system to heat over 2,000,000 acfm of flue gas with very low concentrations of combustible gases from approximately 350°F to over 1300°F while providing adequate turbulence and residence time would be a significant technical issue. Only combustion control is considered a technically feasible option and effective at controlling emissions of CO from a utility boiler.

5.2.4.3 Ranking of Technically Feasible Options

Consumers will be designing the ASCPC boiler to minimize the formation of CO by utilizing combustion controls. Typical combustion controls include monitoring air-to-fuel ratios. As mentioned previously, the proposed ASCPC boiler will employ both LNB and OFA to control NO_x. However, both of these technologies can be effective at minimizing CO as well by monitoring both NO_x and CO (or other indicators of combustion efficiency) simultaneously. Therefore, through the use of proper combustion and optimizing furnace temperature and residence time, CO and NO_x can be effectively minimized from utility boilers.

5.2.4.4 Proposed BACT Emission Limit

The facility is proposing a BACT CO emission limit of 0.125 lb/MMBtu heat input, based on an 8-hour rolling average. This limit is based on combustion controls and good combustion practices. This level of emissions is considered the BACT limit for this process and is lower than many recently issued permits for similar sized SCPC boilers issued in the past several years. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize CO and these emissions will be included as part of the total annual emissions of 4,484.0 tpy. Table 5-6 provides a summary of recent CO BACT limits for new and proposed PC boilers.

Table 5-6. Summary of CO BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.15	Test Protocol	Combustion Controls
LS Power White Pines	NV	1,590	DRAFT	0.15	24-hour rolling	Combustion Controls
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.16	1-hour	Combustion Controls
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.15	24-hour block	Combustion Controls
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.15		Combustion Controls
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.13 coal only 0.15 all fuels	30-day rolling	Combustion Controls
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	0.16		Combustion Controls
American Municipal Power Ohio Generating Station	OH	960	DRAFT	0.15		Combustion Controls

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.10	24-hour rolling	Combustion Controls
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	0.1	24-hour rolling	Combustion Controls
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.14	24-hour rolling	Combustion Controls
LS Power Longleaf	GA	1,200	2007	0.30 0.15	1-hour 30-day rolling	Combustion Controls
Duke Power Cliffside Unit 6	NC	800	2007	0.12		Combustion Controls
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	0.15		Combustion Controls
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	0.10	24-hour	Combustion Controls
City of Springfield Dallman Unit 4	IL	2,440	2006	0.12	3-hour block	Combustion Controls
Omaha Public Power District Nebraska City 2	NE	660	2005	0.16	3-hour rolling	Combustion Controls
Louisiana Gas & Electric Trimble County Generating Station	LA	750	2005	0.10 0.5	30-day rolling 1-hour	Combustion Controls
Louisiana Generating, LLC Big Cajun II	LA	675	2005	0.135		Combustion Controls
City Public Service Spruce 2	TX	750	2005	0.56 0.15	1-hour 12-month	
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.16	30-day rolling	Combustion Controls
TXU Oakgrove 1&2	TX	1,600	2005	0.40 0.15	1-hour 12-month	Combustion Controls
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.12 893 pph	24-hour block Startup/Shutdown	Combustion Controls
Black Hills Corporation Wygen Station I	WY	80	2005	0.15		Combustion Controls
Santee Cooper Cross Units 3&4	SC	1,220	2004	0.16		Combustion Controls
Intermountain Power IPP 3	UT	950	2004	0.15	30-day rolling	Combustion Controls
Longview Power, LLC Longview Power	WV	600	2004	0.11	3-hour rolling	Combustion Controls
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.154	Calendar Day	Combustion Controls
LS Power Plum Point	AR	800	2003	0.16	12-month rolling	Combustion Controls
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.10	30-day rolling	Combustion Controls
Intermountain Power IPP 1 & 2	UT	2,100	2003			
Tucson Electric Springerville 3/4	AZ	800	2002			

5.2.5 Volatile Organic Compounds (VOC)

Volatile organic compounds are emitted from the proposed ASCPC boiler as a result of incomplete combustion of the fuel. Factors affecting the formation of VOC also affect the formation of CO and include air-to-fuel ratio, combustion temperature, residence time, and turbulence (or mixing) of the combustion gases. In addition to the formation of VOC, incomplete combustion also leads to increased emissions of particulate matter, including particulate metals, VOCs, and HAPs. Therefore, methods employed in order to reduce or control emissions of CO tend to reduce emissions of other pollutants as well, including VOCs.

5.2.5.1 Possible Control Technologies

Typically, the same control technologies employed to reduce CO emissions are used to reduce VOC emissions. There are three available control technologies for controlling VOC emissions from a SCPC boiler: (1) catalytic oxidation, (2) thermal oxidation and, (3) efficient combustion. The theory of operation for each of these is exactly the same as for CO. No further write-up on each of these technologies is included. Refer to section 5.2.4.1.

5.2.5.2 Eliminate Technically Infeasible Options

Only combustion control is considered a technically feasible option and effective at controlling emissions of VOC from a utility boiler. To date, the use of post-combustion controls for VOC has not been demonstrated on boiler technology. In addition, post-combustion control to oxidize the VOC in flue gas is typically done on gas streams with a high VOC content. While the flue is expected to have some level of hydrocarbons present, the concentration of these hydrocarbons will be relatively low. Further, the thermal oxidation units are designed in increments of less than 100,000 acfm. The flue gas flow rate for the proposed ASCPC unit is over 2,000,000 acfm.

5.2.5.3 Proposed BACT Emission Limit

The facility is proposing a VOC BACT emission limit of 0.004 lb/MMBtu heat input for the proposed ASCPC boiler, based on a 2-hour average. This limit is based on combustion controls and good combustion practices. This level of emissions is considered the BACT limit for this process and is lower than many recently issued permits for similar sized SCPC boilers issued in the past several years. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize VOC and these emissions will be included as part of the total annual emissions of 129.7 tpy. Table 5-7 provides a summary of recent VOC BACT limits for new and proposed PC boilers.

Table 5-7. Summary of VOC BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.0035	Test Protocol	Combustion Controls
LS Power White Pines	NV	1,590	DRAFT	0.0036	3-hour	Combustion Controls
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.0024	3-hour	Combustion Controls
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.0036	Calendar Day	Combustion Controls
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.0034	Test Protocol	Combustion Controls
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.0036	Test Protocol	Combustion Controls
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	0.06 lb/ton coal		Combustion Controls
American Municipal Power Ohio Generating Station	OH	960	DRAFT	0.0036		Combustion Controls
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.003		Combustion Controls
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	0.003	24-hour	Combustion Controls
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.0035	24-hour	Combustion Controls
LS Power Longleaf	GA	1,200	2007	0.003		Combustion Controls
Duke Power Cliffside Unit 6	NC	800	2007	0.004		Combustion Controls
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	0.0036		Combustion Controls
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	20.4 pph 0.003	3-hour 24-hour	Combustion Controls
City of Springfield Dallman Unit 4	IL	2,440	2006	0.0036	3-hour block	Combustion Controls
LS Power Sandy Creek	TX	800	2006	0.0036 0.0036	1-hour Annual	Combustion Controls
Omaha Public Power District Nebraska City 2	NE	660	2005	0.0034	Test Protocol	Combustion Controls
Louisiana Gas & Electric Trimble County Generating Station	LA	750	2005	0.0032	3-hour rolling	Combustion Controls
Louisiana Generating, LLC Big Cajun II	LA	675	2005	0.015		Combustion Controls

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
City Public Service Spruce 2	TX	750	2005	0.0036 0.0025	1-hour Annual	
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.0036	Test Protocol	Combustion Controls
TXU Oakgrove 1&2	TX	1,600	2005	0.0054 0.0036	1-hour Annual	Combustion Controls
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.004	3-hour block	Combustion Controls
Black Hills Corporation Wygen Station I	WY	80	2005	0.015		Combustion Controls
Santee Cooper Cross Units 3&4	SC	1,220	2004	0.0024		Combustion Controls
Intermountain Power IPP 3	UT	950	2004	0.0027	3-hour	Combustion Controls
Longview Power, LLC Longview Power	WV	600	2004	0.004	3-hour	Combustion Controls
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.0036	1-hour	Combustion Controls
LS Power Plum Point	AR	800	2003	0.02		Combustion Controls
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.0072	30-day rolling	Combustion Controls

5.2.6 Sulfuric Acid Mist (H_2SO_4)

Sulfuric acid mist (SAM or H_2SO_4) is a secondary pollutant formed as a result of sulfur in fuel. During the combustion of coal, the majority of the sulfur is oxidized to form SO_2. The sulfur present in the fuel is released during the combustion process and combines with oxygen at the temperatures present in the combustion zone to form sulfur oxides. The sulfur oxides are primarily SO_2, with lesser amounts of SO_3.

A small portion (typically less than 1%) of the SO_2 is oxidized across the SCR catalyst to form sulfur trioxide (SO_3). In many situations where a dry ESP is the primary control device for particulate, SO_3 is beneficial since it acts to reduce the resistivity of the particulate and allows it to be collected on, and subsequently removed easily from, the ESP plates. However, SO_3 readily reacts with water to form sulfuric acid mist either in the flue gas stream or in the atmosphere after stack discharge.

The use of SCR systems to control NO_x emissions can also contribute to the formation SO_3 emissions due to the presence of catalysts. Typical catalyst construction is made from vanadium pentoxide, which is the active compound responsible for the conversion of SO_2 to SO_3. While these catalysts are known to contribute to SO_3 formation, most SCR systems are designed to limit the conversion to less than 1.0%.

The general equation reaction of SO_2 to H_2SO_4 is as follows:

$$SO_2 + \frac{1}{2}O_2 \rightarrow SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

5.2.6.1 Possible Control Technologies

Because H_2SO_4 is dependent upon the amount of SO_3 in the flue gas stream, control technologies can be designed to target both SO_3 and H_2SO_4. Efforts used to control and minimize the formation of SO_2 and SO_3 will also readily control emissions of H_2SO_4. Therefore, control technologies designed for SO_2 emissions are also effective at reducing H_2SO_4 emissions and include all forms of flue gas desulfurization, including lime and limestone injection. See the BACT discussion for SO_2 in Section 5.2.2.1 for details on flue gas desulfurization.

Based upon the five-step, top-down BACT procedure, Consumers has selected a wet FGD system to control emissions of SO_2 to a level of 0.06 lb/MMBtu. Therefore, further technologies to control emissions of H_2SO_4 are aimed at operating in conjunction with the wet FGD system as a secondary system to control SO_3 formation. The wet FGD system is being designed for a maximum SO_2 inlet concentration of 1.4 lb/MMBtu. Conservatively assuming a conversion rate of 2.5% SO_2 to SO_3 across the SCR catalyst and some acid gas deposition in the air heater yields a maximum SO_3 concentration in the flue gas of 0.03 lb/MMBtu exiting the air heater.

Two primary technologies exist to control sulfuric acid mist from utility boilers is to include a wet ESP on the back end of the air quality control system downstream of the fabric filter or dry ESP, and hydrated lime injection upstream of the particulate control device. The following BACT analysis addresses the feasibility of installing these technologies.

Wet ESP

Wet EPSs are primarily designed for control of condensable particulate emissions, and have been demonstrated to reduce emissions of SO_3 and H_2SO_4 from high sulfur coals. See the BACT discussion for particulate matter in Section 5.2.1.1 for details on wet ESP technology.

SO_3 will be removed from the flue gas by the fabric filter even in the absence of any dry lime injection system to a level of 75% and control an additional 25% in the wet FGD. Consequently, the wet ESP is based upon control of 0.0057 lb/MMBtu for SO_3 exiting the wet FGD system.

Hydrated Lime Injection

Hydrated lime, also known as slaked lime, is produced by combining lime with water to form the chemical compound $Ca(OH)_2$. After being mixed with water it is dried to remove excess water. Therefore, hydrated lime is a dry powder that can be injected into the flue gas upstream of the fabric filter as a polishing mechanism to reduce SO_3, a precursor to sulfuric acid mist formation. Typically, hydrated lime injection is used in combination with flue gas desulfurzation processes as a “trimming” mechanism to control SO_3 and is not used as the primary FGD control technology.

In the hydrated lime injection system, the inlet temperature to the fabric filter is monitored continuously for temperature. Once the inlet temperature of the fabric filter is within 15°F of the sulfuric acid dewpoint, the hydrate lime injection system will operate. The data control system will also monitor the SO_2 concentration of the flue gas stream and establish a constant injection rate to control H_2SO_4 based on a calculated SO_3 concentration. The SO_3 concentration is determined based on a conversion of SO_2 and SO_3, and the H_2SO_4 concentration is calculated based upon the concentration of SO_3 and moisture.

As discussed above, the hydrated lime injection system would be installed prior to the fabric filter and after the air heater. Therefore, the hydrated lime injection system is based upon control of 0.03 lb/MMBtu for SO_3 prior to the baghouse.

5.2.6.2 Eliminate Technically Infeasible Options

Both the wet ESP and hydrated lime injection system are considered technically feasible options and effective at controlling emissions of SO_3 and acid gases. In general, a wet ESP is used on utility boilers firing higher sulfur bituminous coals where the inlet loading to the wet ESP is relatively high. For utility boilers primarily designed to burn lower sulfur coals, such as that proposed for this project, dry systems provide a much better alternative as the need to handle additional waste water is avoided.

5.2.6.3 Ranking of Technically Feasible Options

Wet ESPs are effective at controlling SO_3 emissions and acid gases and generally provide superior removal efficiencies to the hydrated lime system, but at a significant cost. Table 5-8 provides a ranking of the available control technologies for sulfuric acid mist beyond the use of a wet FGD system as the primary control technology for SO_2.

Table 5-8. Ranking of SO_3 and H_2SO_4 Control Technologies

Control Technology	Control Efficiency (%)
Hydrated Lime	43
Wet ESP	90

5.2.6.4 Energy, Environmental, and Economic Impacts of Control Options

Currently, control technologies specific to H_2SO_4 removal are not employed except for units fueled exclusively with high sulfur coals. For the lower sulfur coals, FGD systems are used to control SO_2 (and SO_3) emissions, which is a precursor to acid gas. Installing a dedicated dry system to control SO_3 emissions is used in certain circumstances for trimming purposes and installed upstream of the particulate control device. However, in circumstances where a dry ESP is used as the primary particulate control device, controlling SO_3 emissions can lead to an increase in particulate emissions due to buildup on the plates. SO_3 has been widely demonstrated to enhance the performance of dry ESPs and minimizing SO_3 in the flue gas can cause performance penalties on the ESP.

Economic

The total capital and operating cost for the hydrated lime injection system is summarized in Table D-1. This table shows that a hydrated lime system of the size necessary for the proposed ASCPC boiler is approximately $8.25 million for a 930 MW unit similar to the proposed ASCPC unit whereas for a wet ESP system capital costs are approximately $176 million (Table D-2). Further, annual operating cost for the wet ESP is estimated to be much higher than for hydrated lime injection system with no increase in acid gas control. In summary, installation of a hydrated lime injection system designed for approximately 43% removal of SO_3 will cause an incremental cost increase of $1,918.30 per ton removed. Installation of the wet ESP will control H_2SO_4 at an incremental cost of $154,205.91 per ton removed.

In summary, the wet ESP will be much more expensive to purchase and operate when compared to a hydrated lime injection system and will not provide greater reductions in SO_3 and control of H_2SO_4.

Environmental

The hydrated lime injection system uses slaked lime injection prior to the fabric filter to react with the SO3. Because the slaked lime is a powder, additional inlet loading to the fabric filter will result and require an appropriately sized system. Further, additional ash handling will be required to an amount equal to the injection rate of hydrated lime that must be handled and disposed.

A wet ESP uses water sprays in conjunction with electrical currents to removal acid gases and SO_3. Consequently, a wet ESP will require additional facilities for treatment and handling of wastewater.

Energy

Wet ESPs typically have a higher parasitic energy consumption load and cause a large energy penalty to the overall power system as compared to a dry hydrated lime system. Primarily, the highest energy requirements for a wet ESP include pressure drop and water treatment.

5.2.6.5 Proposed BACT Emission Limit

The proposed BACT emission limit for H_2SO_4 is 0.004 lb/MMBtu, based on a 3-hour average. Consumers proposes to install a new hydrated lime system to control SO_3 emissions from the combustion of the proposed coals. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize sulfuric acid mist formation and these emissions will be included as part of the total annual emissions of 143.5 tpy. Table 5-9 provides a summary listing of recent BACT determinations and permit levels for similar pulverized coal units.

Table 5-9. Summary of H_2SO_4 BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	0.004	Test Protocol	Dry FGD
LS Power White Pines	NV	1,590	DRAFT	0.0034	3-hour	Dry FGD
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	0.0075		Wet FGD
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.005	24-hour	Wet FGD
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.004		Wet ESP
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.004	Test Protocol	Wet FGD Wet ESP
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	NA	NA	NA
American Municipal Power Ohio Generating Station	OH	960	DRAFT	0.0075		Wet ESP
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.004	3-hour	Hydrated Lime
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	NA	NA	NA
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.10	24-hour	Dry FGD Wet ESP
LS Power Longleaf	GA	1,200	2007	0.005	3-hour	Dry FGD
Duke Power Cliffside Unit 6	NC	800	2007	0.005		Wet FGD Wet ESP
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	0.0037		Wet FGD
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	0.004	3-hour	Wet FGD
City of Springfield Dallman Unit 4	IL	2,440	2006	0.005	3-hour block	Wet FGD Wet ESP

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
LS Power Sandy Creek	TX	800	2006	0.016 0.0037	1-hour Annual	Dry FGD
Omaha Public Power District Nebraska City 2	NE	660	2005	0.0042	Test Protocol	Dry FGD
Louisiana Gas & Electric Trimble County Generating Station	KY	750	2005	0.0038	3-hour rolling	Wet ESP
Louisiana Generating, LLC Big Cajun II	LA	675	2005	NA	NA	NA
City Public Service Spruce 2	TX	750	2005	0.0055 0.0037	1-hour Annual	
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.00716		Wet FGD
TXU Oakgrove 1&2	TX	1,600	2005	0.0143 0.0037	1-hour Annual	
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.005	3-hour block	Wet FGD Wet ESP
Santee Cooper Cross Units 3&4	SC	1,220	2004	0.0075	3-hour	Wet FGD
Intermountain Power IPP 3	UT	950	2004	0.0044	24-hour block	Wet FGD
Longview Power, LLC Longview Power	WV	600	2004	0.0075	3-hour	Hydrated Lime
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.00421		Dry FGD
LS Power Plum Point	AR	800	2003	0.0061		Dry FGD
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.00497	30-day rolling	Wet ESP

NOTE: The proposed HF emission limit of 0.00017 lb/MMBtu has been established through the case-by case-MACT included in Appendix J.

5.2.7 Fluorides (as HF)

Fluoride is a trace element found in most coals. Fluorides (as HF) are emitted during the combustion of coal when the fluoride reacts with hydrogen. At standard conditions, hydrogen fluoride or hydrofluoric acid (HF) is present as a liquid. However, at temperatures of a utility boiler, the HF is emitted as a gas within the flue gas stream.

The emissions of HF are directly dependent on the level of fluorine present in the coal. In general, as presented in Section 3, the concentration of fluorine in the coal is relatively low.

5.2.7.1 Possible Control Technologies

HF readily reacts and combines with alkaline materials, including calcium and sodium. Therefore, efforts to reduce SO_2 and SO_3 will also effectively control emissions of HF. In fact, fluorides react and absorb to calcium more quickly than sulfur compounds. Therefore, flue gas desulfurization systems will produce greater reductions in HF than SO_2 and SO_3. See the discussion regarding sulfur dioxide control technologies in Section 6.2.2.

5.2.7.2 Eliminate Technically Infeasible Options

Systems have not been designed to primarily control emissions of HF. Instead, HF reduction is achieved through the flue gas desulfurization systems.

5.2.7.3 Ranking of Technically Feasible Options

Installation of a dedicated HF control system is not feasible. As mentioned previously, HF reductions are achieved through existing SO_2 and SO_3 controls.

5.2.7.4 Energy, Environmental, and Economic Impacts of Control Options

Because dedicated control systems for HF are not feasible, an assessment of energy, environmental, and economic impacts is not necessary.

5.2.7.5 Proposed BACT Emission Limit

The proposed BACT emission limit for HF is 0.0003 lb/MMBtu, based on a 2-hour average. Consumers will be installing a new hydrated lime system to control SO_3 emissions, a wet FGD system to control SO_2 and fabric filter to collect particulate. The proposed use of these systems in combination will be used to achieve the proposed level of emission. Finally, as mentioned in Section 5.1.1, BACT for periods of startup and shutdown will be governed by work practice standards to minimize HF and these emissions will be included as part of the total annual emissions of 8.76 tpy. Table 5-10 provides a summary listing of recent BACT determinations and permit levels for similar pulverized coal units.

Table 5-10. Summary of HF BACT Limits for New and Proposed PC Boilers

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Sunflower Electric Power Cooperative Holcomb Generating Station	KS	700	DRAFT	NA	NA	NA
LS Power White Pines	NV	1,590	DRAFT	0.00097	3-hour	Dry FGD
Santee Cooper Pee Dee Generating Station	SC	1,220	DRAFT	NA	NA	NA
Wisconsin Public Service Weston 4	WI	500	DRAFT	0.000217		Wet FGD
Florida Power & Light Florida Glades Power Plant	FL	1,760	DRAFT	0.00023		Wet ESP
Florida Municipal Power Taylor Energy Center	FL	800	DRAFT	0.00047	Test Protocol	Wet FGD Wet ESP
PacificCorp Hunter Power Plant – Unit 4	UT	575	DRAFT	0.0004		
American Municipal Power Ohio Generating Station	OH	960	DRAFT	NA	NA	NA
Toquop Energy, LLC Toquop Energy Project	NV	750	DRAFT	0.00024	3-hour	Hydrated Lime
Sierra Pacific Resources Ely Energy Center	NV	750	DRAFT	NA	NA	Dry FGD
WE Energies Oak Creek Expansion (Elm Road)	WI	1,230	2007	0.00044		Dry FGD Wet ESP
LS Power Longleaf	GA	1,200	2007	0.00095	3-hour block	Dry FGD
Duke Power Cliffside Unit 6	NC	800	2007	NA	NA	Wet FGD Wet ESP
Weston Farmers Electric Cooperative Hugo Generating Station	OK	750	2007	NA	NA	NA
Sithe Global Power, LLC Desert Rock Energy Center	AZ	1,500	2006	0.00024	3-hour	Wet FGD
City of Springfield Dallman Unit 4	IL	2,440	2006	NA	NA	NA
Omaha Public Power District Nebraska City 2	NE	660	2005	0.004	Test Protocol	Dry FGD
Louisiana Gas & Electric Trimble County Generating Station	KY	750	2005	0.002	3-hour	Wet FGD
Louisiana Generating, LLC Big Cajun II	LA	675	2005	NA	NA	NA
City Public Service Spruce 2	TX	750	2005	0.008 0.0008	1-hour Annual	
Kansas City Power & Light Iatan Unit 2	MO	930	2005	0.004	Test Protocol	Wet FGD
TXU Oakgrove 1&2	TX	1,600	2005	0.01656 0.00074	1-hour Annual	
Peabody Energy Prairie State Generating Co., LLC	IL	1,500	2005	0.00026	3-hour	Wet FGD Wet ESP

Facility Name	State	Size (MW)	Year Issued Status	Limit (lb/MMbtu)	Averaging Period	Control Technology
Santee Cooper Cross Units 3&4	SC	1,220	2004	0.0003		
Intermountain Power IPP 3	UT	950	2004	0.0005	3-hour	Wet FGD
Longview Power, LLC Longview Power	WV	600	2004	0.00001	3-hour	Hydrated Lime
MidAmerican Energy Council Bluffs – Unit 4	IA	750	2003	0.0009		Dry FGD
LS Power Plum Point	AR	800	2003	0.00044		Dry FGD
Peabody Energy Thoroughbred Generating Co.	KY	1,500	2003	0.000159	30-day rolling	Wet ESP

5.2.8 Summary of Proposed BACT Limits for the ASCPC Boiler

The control technology analysis provided for the proposed ASCPC boiler was conducted in accordance with the USEPA recommended “top-down” approach for determining emission limits for all NSR pollutants experiencing an increase greater than the appropriate significant thresholds. Consistent with the definition of BACT, Consumers proposes the work practice standard during periods of startup and shutdown identified in Section 5.1.1.

Table 5-11 provides a summary of the BACT limits proposed for this project.

Table 5-11. Summary of Proposed BACT/MACT Limits for ASCPC Boiler

Pollutant	Emission Limit Lb/MMBtu	Averaging Time
Particulate Matter (PM)	0.011	2-hour
$PM_{10}/PM_{2.5}$	0.024	2-hour
Sulfur Dioxide (SO_2)	0.06	30-day rolling
Nitrogen Oxides (NO_x)	0.05	30-day rolling
Carbon Monoxide (CO)	0.125	30-day rolling
Volatile Organic Compounds (VOC)	0.0034	2-hour
Sulfuric Acid Mist (H_2SO_4)	0.004	2-hour
Fluorides (as HF)	0.00017	2-hour

NOTE: Auxiliary Boiler VOC limit of 0.0013 lb/MMBtu is based on the MACT demonstration in Appendix K. This MACT emission limit supersedes the Auxiliary Boiler BACT VOC determination included in this section and is included in Table 5-12.

5.3 AUXILIARY BOILER

To assist during startup of the proposed ASCPC boiler, one (1) 220 MMBtu/hr natural gas-fired boiler will be utilized to heat the combustion air injected into the boiler. The auxiliary boiler will primarily be used during startup periods and is shutdown when the ASCPC unit reaches approximately 30% load, and may be used to provide auxiliary steam loads (i.e., steam for building heat) when the ASCPC is down. Because the auxiliary boiler is part of the overall project and ancillary equipment associated with the ASCPC unit, a control technology review is required.

As mentioned previously, the auxiliary boiler will be fired exclusively with pipeline natural gas from the Consumers transmission or distribution system. The boiler will not have the ability to burn any liquid or solid fuels. Use of natural gas is considered BACT for this process for all NSR regulated pollutants. A comprehensive summary of recent BACT determinations is provided in Table D-5 while pollutant-specific determinations are summarized at the end of each section.

5.3.1 Particulate Matter (PM_{10}/$PM_{2.5}$)

Natural gas does not contain ash or other solid constituents. Consequently, emissions of filterable particulate are extremely low and usually below detection limits. The formation of small amounts of particulate matter can occur during the combustion process as a result of incomplete combustion of heavier weight hydrocarbons that form condensable particulate. Additionally, particulate matter emissions can occur when the boiler is operating in an oxygen rich environment due to poor air-to-fuel ratio and mixing.

Emissions of PM/PM_{10}/$PM_{2.5}$ have been estimated using section 1.4 of the USEPA AP-42, fifth edition for natural gas combustion. The AP-42 has established a total filterable particulate emission factor of 1.9 lb/MMscf, which is equivalent to 0.0019 lb/MMBtu. For total PM, the emission factor is 7.6 lb/MMscf, which is equivalent to 0.007 lb/MMBtu. The conversion from lb/MMscf to lb/MMBtu assumes a heat content of 1,020 Btu/scf for pipeline natural gas.

Use of pipeline natural gas for the auxiliary boiler is considered to be the best fuel alternative for minimizing emissions of particulate. The filterable PM and total PM limits of 0.0019 lb/MMBtu and 0.007 lb/MMBtu are consistent with other recent permits for natural gas-fired auxiliary boilers and represent BACT for the emission unit.

5.3.2 Sulfur Dioxide (SO_2)

Natural gas contains only trace amounts of sulfur available for conversion to sulfur dioxide. Therefore, emissions of SO_2 are extremely low and not usually part of an emissions test for such a small unit. Typical sulfur content of pipeline natural gas contains less than 0.5 grains per 100 standard cubic foot (gr/100 scf). In addition, very small quantities of other sulfur compounds are known to exist in natural gas and primarily include hydrogen sulfide (H_2S). H_2S readily converts to SO_2 during the combustion process and combustion is considered a control technology for H_2S. Nonetheless, the total sulfur compounds of pipeline natural gas are so small that additional controls beyond direct combustion are unnecessary.

The AP-42 has established an SO_2 emission factor of 0.6 lb/MMscf, which is equivalent to 0.0006 lb/MMBtu. Use of pipeline natural gas for the auxiliary boiler is considered to be the best fuel alternative for minimizing emissions of SO_2. The SO_2 limit of 0.0006 lb/MMBtu is consistent with other recent permits for natural gas-fired auxiliary boilers and represents BACT for the emission unit.

5.3.3 Oxides of Nitrogen (NO_x)

Natural gas contains only minor amounts of nitrogen and the contribution of this nitrogen in fuel is insignificant in the formation of NO_x (fuel NO_x) from natural gas combustion. Instead, the primary contribution to NO_x formation with natural gas combustion is from thermal NO_x as a result of the air-to-fuel ratio and operating procedures.

5.3.3.1 Possible Control Technologies

The same control options for NOx for the proposed ASCPC boiler presented in Section 5.2.3 would be applicable to the auxiliary boiler. Refer to Section 5.2.3 for the possible control options.

5.3.3.2 Eliminate Technically Infeasible Options

Both combustion controls and add-on control systems are considered technically feasible options and effective at controlling emissions of NO_x from a natural gas-fired boiler. In contrast to the ASCPC boiler where the primary mechanism for NO_x formation is a result of fuel-bound nitrogen, in natural gas-fired boilers the primary contributor to NO_x formation is from thermal NO_x. As previously mentioned, the auxiliary boiler will only be used during startup of the ASCPC boiler to help bring the combustion air and furnace box up to the appropriate temperature when pulverized coal can be added. While the auxiliary boiler has been evaluated based on continuous operation with no restriction on operating hours, in reality, it is expected to operate less than 20% of the year.

In general, SNCR systems are better suited for industrial processes that produce high temperature flue gas streams and not for the relatively lower flue gas temperatures of a natural gas-fired boiler. Further, NO_x removal efficiencies of SNCR systems are not as high as with SCR systems and tend to be limited to less than 50% without combustions controls, especially in situations where the concentration of NO_x is below 200 ppm. Thus, use of SNCR in new boiler applications that include state-of-the-art combustions is not an ideal application for this technology. Therefore, SNCR has been eliminated from further consideration.

Reburn and OFA have not been commercially demonstrated for natural gas-fired package boilers. These technologies seek to limit the formation of NOx by vertical combustion staging in the furnace of a field-erected boiler. The auxiliary boiler to be used as part of this project will be a package boiler. Package boilers do not have the volume or residence time to accommodate these two technologies. Therefore, reburn and OFA have been eliminated from further consideration.

5.3.3.3 Ranking of Technically Feasible Options

Consumers will be designing the auxiliary boiler to minimize the formation of NO_x by utilizing combustion controls, including LNBs and FGR technology. Both of these technologies are readily available for new boiler installation and have proven very effective at limiting the formation of thermal NO_x. In fact, use of both LNB and FGR will limit NO_x emissions to a level of 15 ppm, which is considered the baseline NO_x limit for this package boiler.

The addition of an SCR at the outlet of the auxiliary boiler would reduce NO_x emissions by an additional 80% to 3 ppm.

5.3.3.4 Energy, Environmental, and Economic Impacts of Control Options

As mentioned in Section 5.3.3.3, Consumers will purchase the natural gas-fired auxiliary boiler with both LNB and FGR technology. Therefore, the discussion regarding energy, environmental, and economic impacts is limited to SCR.

Economic

The total capital and operating cost for a SCR to be included with the auxiliary boiler is presented in Table D-3. The estimated capital cost to purchase the SCR system is $900,000 and the annual operating costs are estimated to be $576,293. These costs lead to incremental cost to control NOx to 3 ppm of nearly $40,000 per ton removed.

Environmental

SCR requires use of urea or ammonia injection to react with NOx. If monitored closely, the injection rate of urea can cause un-reacted ammonia to escape with the flue gas causing excess ammonia emissions and problems with condensable particulate.

Energy

SCR systems require use of energy to operate properly. It is estimated that approximately 10 kW would be required to operate the SCR system.

5.3.3.5 Proposed BACT Emission Limit

The proposed BACT NO_x limit based on this top-down analysis is 15 ppm, which is equivalent to 0.018 lb/MMBtu, based on an annual average. Consumers proposes LNB and FGR combustion controls to achieve this level of NO_x emissions from the combustion of natural gas. This limit is well within the established range for similar and smaller sized boilers, is consistent with other recent permits for natural gas-fired auxiliary boilers, and represents BACT for the emission unit.

5.3.4 Carbon Monoxide (CO)

Natural gas consists primarily of methane (CH_4). As part of the combustion process, carbon compounds are released. The vast majority of carbon compounds released during combustion are CO and CO_2. As a result of incomplete combustion, CO is released. However, emissions of CO and NO_x are generally inversely related during the combustion process. Specifically, efforts to minimize the emissions of NO_x can result in some increased emissions of CO, and vice-versa. Because of air quality concerns, the design of boilers to address this trade-off sides with the minimization of NO_x. The auxiliary boiler will include LNB and FGR technology to minimize the formation of thermal NO_x to the maximum extent possible, rather than optimize for minimum CO emissions.

To minimize the resulting potential CO emissions, boilers can be designed with combustion controls to maintain optimum air-to-fuel ratios. Since CO emissions can be expected to increase as a result of LNB and OFA, and because the boiler will be rated at 220 MMBtu/hr, an emission factor of 0.035 lb/MMBtu has been used as the design basis for the boiler. This CO limit is well within the established range for similar and smaller sized boilers, is consistent with other recent permits for natural gas-fired auxiliary boilers, and represents BACT for the emission unit.

5.3.5 Volatile Organic Compounds (VOC)

As mentioned previously for the ASCPC boiler, emissions of VOC are proportionally related to CO. Natural gas consists of hydrocarbons that are released during the combustion process. As a result of incomplete combustion, both VOC and CO are released. Emissions of VOC and NO_x are inversely related during the combustion process and efforts to minimize the emissions of NO_x can result in increased emissions of VOC. As mentioned previously, the auxiliary boiler will include LNB and FGR technology to minimize the formation of thermal NO_x. Consequently, minor emissions of VOC emissions can be expected.

Section 1.4 of the USEPA AP-42, fifth edition for natural gas combustion has established a VOC emission factor of 5.5 lb/MMscf for large wall-fired boilers (>100 MMBtu/hr) regardless of the control technology installed for NO_x. This level of emissions is equivalent to 0.005 lb/MMBtu.

The VOC limit of 0.005 lb/MMBtu is consistent with other recent permits for natural gas-fired auxiliary boilers and represents BACT for the emission unit.

5.3.6 Acid Gases (H_2SO_4, HF, TRS)

As mentioned previously, only trace amounts of S and H_2S are present in natural gas. Due to oxidation of the sulfur compounds in the boiler and use of good combustion controls, the sulfur bearing compounds will be oxidized to SO_2 rather than to form total reduced sulfur (TRS) compounds. Additionally, other acid gases, including HF, are not expected due to the lack of any measurable fluorine in the pipeline natural gas. Therefore, establishing a BACT limit for these acid gases is not appropriate.

5.3.7 Summary of Proposed BACT Limits for the Auxiliary Boiler

The control technology analysis provided for the proposed auxiliary boiler was conducted in accordance with the USEPA recommended "top-down" approach and MDEQ Operational Memorandum 20 for determining emission limits for all NSR pollutants experiencing an increase greater than the appropriate significant thresholds.

Table 5-12 provides a summary of the BACT limits proposed for the auxiliary boiler.

Table 5-12. Summary of Proposed BACT/MACT Limits for the Auxiliary Boiler

Pollutant	Emission Limit Lb/MMBtu	Averaging Time
Particulate Matter (PM)	0.0019	2-hour
$PM_{10}/PM_{2.5}$	0.007	2-hour
Sulfur Dioxide (SO_2)	0.0006	30-day rolling
Nitrogen Oxides (NO_x)	0.018	30-day rolling
Carbon Monoxide (CO)	0.035	30-day rolling
Volatile Organic Compounds (VOC)	0.0013	2-hour
Sulfuric Acid Mist (H_2SO_4)	NA	NA
Fluorides (as HF)	NA	NA

5.4 EMERGENCY GENERATOR

Consumers will be purchasing a new diesel fuel-driven emergency generator rated at 2,000 kW (2,980 hp) to provide safe plant shutdown and critical load operation in the event of a power grid failure. The fuel chosen for the emergency generator is ultra low sulfur (0.0015%) diesel. Because the generator will only be used in emergency situations, it will be limited to not more than 500 hours per year of operation.

The generator will be subject to NSPS Subpart IIII for new non-road compression ignition engines. Subpart IIII establishes emission limits for non-methane hydrocarbons (NMHC) + NO_x, CO, and PM. Unlike most other NSPS emission limits, Subpart IIII places the requirements on the manufacturers of these engines to certify that the emission limits will be met for each engine sold. The obligations of the owner/operator are to purchase a certified engine, and operate the engine according to manufacturer's specifications. Therefore the purchase, maintenance and operation of an engine that is in compliance with Subpart IIII for emergency use only (i.e., limiting the hours of operation to not more than 500 hours per year), and the use of ultra low sulfur diesel fuel is considered BACT. BACT for emergency generators has traditionally been limiting of the hours of operation to less than 500 hours, and the use of low sulfur diesel fuel. Purchasing engines that meet the NSPS Subpart IIII requirements along with the use of ultra low sulfur diesel fuel will result in emissions lower than almost all historic BACT determinations. A comprehensive review of the RBLC for emergency diesel engines revealed not a single permitted source that relied on additional controls to achieve the BACT requirements.

Subpart IIII does not contain an emission limit for PM_{10}. In addition, there are no total PM_{10} limits listed in the RBLC database. The only available information on total PM_{10} emissions from diesel RICE is from AP-42 Ch. 3.4 for large engines. The AP-42 information for PM_{10} and the NSPS limits were used to calculate the potential emission limits for the emergency generator and are listed in Section 3, Table 3-16.

5.4.1 Possible Control Technologies

Consumers reviewed the RBLC database, as well as the RICE NSPS (Subpart IIII) and NESHAP (Subpart ZZZZ), to determine possible control technologies applicable to emergency engines.

Possible control technologies to reduce emissions from diesel fuel fired RICE include good combustion practices, the use of low sulfur fuels and after-treatment technologies such as selective catalytic reduction (SCR), non-selective catalytic reduction (NSCR) or NO_x adsorbers to reduce NO_x emissions, oxidation catalysts to reduce CO and VOC, catalyzed diesel particulate filters (CDPF) to reduce PM, CO, and VOC emissions, or electrostatic precipitators (ESP) to reduce filterable particulate emissions.

The results of this analysis show that the only feasible control technologies to reduce emissions from emergency RICE is through the use of low sulfur fuels, good combustion practices and proper engine operation. Post combustion and after-treatment controls are not feasible for emergency engines due to the fact that an emergency engine rarely operates and therefore has insignificant emissions (e.g. the largest pollutant is NO_x from the emergency engine at 7.8 tpy). As such, add-on control is not economically feasible. USEPA affirms this in the preamble to the proposed Compression Ignition RICE NSPS where it states:

> *The use of add-on controls such as CDPF, oxidation catalyst, and NO_x adsorber could not be justified as BDT [best demonstrated technology] due to the cost of the technology relative to the emission reduction that would be obtained.* [FR: Vol. 70 No. 131, July 11, 2005]

5.4.2 Proposed BACT for Emergency Engines

BACT is an emission limit that represents the best level of control taking into consideration energy, economic, and non-air quality environmental impacts on a case-by-case basis. The regulations governing BACT allow the Department to make a determination that "technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible." In such case a "design, equipment, work practice, operational standard, or combination thereof", may be prescribed instead to satisfy the requirement for BACT. BACT for emergency engines has traditionally been based on engine design, good operating practices, and low sulfur fuel. The proposed BACT will not have any adverse environmental or energy impacts.

Since BACT applies at all times and during all periods of operation, the method of measurement used to determine compliance with the limit is an integral part of the overall BACT limit. As such, work practice standards are often used in lieu of an emission limit or as an additional BACT requirement to ensure compliance with an emission limit for sources that have unique or complicated measurement issues. Consumers evaluated the feasibility of establishing BACT emission limits, and found that the NSPS Subpart IIII would represent BACT for PM, NO_x, CO, VOC and SO_2 (through the use of ultra low sulfur fuel) and PM_{10} BACT would be 0.0573 lb/MMBtu. However, demonstrating compliance with these emission limits through stack testing or continuous emission monitoring systems (CEMS) is not practical since the engine will be operated only for maintenance purposes or during an emergency. As such, the establishment of work practice standards is necessary for continued compliance with BACT. The following work practice standards will ensure compliance with the BACT emission limits:

- The emergency engine will be purchased new from the manufacturer, and will be certified to meet the NSPS requirements for the size, model year and utilization for that engine. The engine will meet the emission limits, operation and maintenance requirements stipulated in the NSPS. The engine will also be maintained to provide for continuous compliance with the required NSPS emission limits, and Consumers will follow manufacturer recommendations for proper and efficient operation.

- The engine will use ultra low diesel fuel that will be 15 ppm sulfur by weight (0.0015%) or less. This will result in lower SO_2 and PM/PM_{10} emissions than identical engines using diesel fuel with a higher sulfur content fuel.

- The engines will only be operated in an emergency situation, when the normal power source is interrupted, or occasional spinning of the engine for exercise to ensure that it is in ready mode in the event there is an emergency. The engine will operate no more than 500 hours per year.

These work practice standards and meeting the applicable NSPS emission limits is the best method for providing BACT.

The pollutant-specific analysis is discussed in further detail below.

Particulate Matter (PM/PM_{10})

PM/PM_{10} is produced from the incomplete combustion of diesel fuel inside the cylinders that form carbonaceous matter, and from sulfate compounds resulting from the oxidation of sulfur in the fuel. Engine lubricants can also contribute to the emissions of PM/PM_{10} due to blow-by of lubricating oils which condense in the exhaust stream. Since the emergency generator will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, PM/PM_{10} will be minimized.

Consumers reviewed the RBLC to determine the emissions of PM/PM_{10} from similar sized emergency generators for determining BACT. All of the PM/PM_{10} is identified as filterable particulate in the RBLC. There is no PM_{10} specific data. Table 5-13 summarizes the RBLC findings.

Table 5-13. Summary of PM/PM_{10} BACT Limits for Emergency Generators > 1,000 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	2,168 hp	0.69 pph	0.14	NA	Good combustion practices; low sulfur fuel
Sabine Pass LNG Terminal	LA	2,220 hp	1.96 pph	0.40	NA	Good combustion practices
Genova OK I Power Plant	OK	750 kW (~1,000 hp)	0.033 lb/MMBtu	0.10	500 hr/yr	Good combustion practices
Port Washington Generating Station	WI	7.6 MMBtu/hr (~1,100 hp)	0.89 pph	0.37	500 hr/yr	0.05% wt sulfur fuel oil
Horseshoe Energy Project	OK	1,000 hp	0.1 lb/MMBtu	0.32	NA	Low ash diesel fuel
Mansfield Mill	LA	1,100 hp	2.4 pph	0.99	NA	Preventive maintenance
Arizona Clean Fuels Yuma	AZ	10.9 MMBtu/hr (~1,200 hp)	0.2 g/kW-hr	0.15	NA	NA

A review of the RBLC indicates that good combustion control is the most stringent requirement for emergency generators. The PM emission limits range between 0.10 g/hp-hr up to 1.03 g/hp-hr. The NSPS limit for the emergency engine is 0.20 g/kW-hr, which is equivalent to 0.15 g/hp-hr. The Genova OK I Power Plant and Creole Trail LNG Terminal emergency generators have a limit more stringent than that proposed for the ASCPC Project emergency generator which is 0.0573 lb/MMBtu. All of the other engines identified in Table 5-13 with a similar engine rating to the proposed emergency engine are greater than the NSPS PM limit of 0.15 g/hp-hr. None of these engines rely on add-on controls.

There are no total PM_{10} limits listed in the RBLC database. The only available information on total PM_{10} emissions from diesel RICE is from AP-42 Ch. 3.4. The AP-42 document shows that for large diesel fired engines the total PM_{10} emission rate is 0.0573 lb/MMBtu, which is 22 percent higher than the NSPS filterable PM emission rate of 0.047 lb/MMBtu (0.20 g/kW-hr). At these levels, the annual PM and total PM_{10} emissions would be 0.24 tpy and 0.30 tpy, respectively. At these low levels, add-on control technology would not be cost effective.

Therefore, Consumers believes that if BACT were to be represented by an emission limit the limit would be 0.20g/kW-hr for PM and 0.0573 lb/MMBtu (0.244 g/kW-hr) for emissions of PM_{10}.

Sulfur Dioxide (SO_2)

Sulfur dioxide emissions from RICE are a function of the sulfur content in the fuel that is burned in the RICE. Consumers will use ultra low sulfur diesel fuel with a sulfur content of not more than 0.0015 percent by weight. A review of the RBLC indicates that no add on controls are required and that BACT is the use of low sulfur diesel fuel.

Table 5-14. Summary of SO_2 BACT Limits for Emergency Generators > 1,000 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Redbud Power Plant	OK	1,818 hp	0.4 lb/MMBtu	1.27	NA	NA
Horseshoe Energy Project	OK	1,000 hp	0.05 lb/MMBtu	0.16	NA	Low Sulfur Diesel Fuel
Mansfield Mill	LA	1,100 hp	2.2 pph	0.91	NA	Preventive maintenance

As shown, the use of ultra low sulfur diesel fuel with a sulfur content of 15 ppm (0.0015 percent by weight), which is equivalent to 0.005 g/hp-hr, is more stringent than any other source in the RBLC and represents BACT for the proposed emergency generator.

Oxides of Nitrogen (NO_x)

NO_x is present in the exhaust gas in two forms: thermal NO_x and fuel NO_x. Thermal NO_x is formed when combustion air is heated to a temperature that causes the nitrogen and oxygen in the combustion air to disassociate to form nitrogen oxide (NO) with lesser amounts of nitrogen dioxide (NO_2). Fuel NO_x is formed as a result of the nitrogen in the fuel combining with the oxygen in the combustion air.

Various methods exist to remove fuel bound nitrogen. Nitrogen is removed during the refining process, and diesel fuel is refined such that most of the nitrogen is removed from the fuel. Thermal NO_x is controlled via combustion design, which includes staging combustion, utilizing less compression, or an add-on control device such as SCR, non-selective catalytic reduction (catalytic converters), or NO_x adsorbers.

Since the emergency generator will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, NO_x will be minimized.

Consumers has reviewed the RBLC to determine the emissions of NO_x from similar sized emergency generators for determining BACT. Table 5-15 summarizes the RBLC findings.

Table 5-15. Summary of NO_x BACT Limits for Emergency Generators > 1,000 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	2,168 hp	37.95 pph	7.94	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	2,220 hp	33.77 pph	6.90	NA	Good combustion practices
Genova OK I Power Plant	OK	750 kW	3.01 lb/MMBtu	9.56	500 hr/yr	Good combustion practices
Port Washington Generating Station	WI	7.6 MMBtu/hr (~1,100 hp)	27.36 pph	11.3	NA	Good combustion practices
Rebud Power Plant	OK	1,818 hp	0.024 lb/bhp-hr	10.9	NA	NA
Horseshoe Energy Project	OK	1,000 hp	4.41 lb/MMBtu	15.4	NA	Good combustion practices
Mansfield Mill	LA	1,100 hp	34 pph	14.0	NA	Preventive maintenance
AEP Waterford Energy, LLC	OH	1,341 hp	0.82 tpy	1.11	500 hr/yr	NA
ADM Corn Processing – Cedar Rapids	IA	1,500 kW (~2,000 hp)	4.5 g/bhp-hr	4.5	500 hr/yr	NA

A review of the RBLC indicates that emergency generators have not been required to install additional NO_x controls because of intermittent operation. The NO_x emissions range between 1.11 g/hp-hr to 15.4 g/hp hr. The NSPS specifies a limit for total NMHC + NO_x as 6.4 g/kW-hr, which is equivalent to 4.3 g/hp-hr. The only source listed in Table 5-15 that contains a NO_x limit more stringent than the total NMHC and NO_x NSPS limit is AEP Waterford Energy, LLC.

The potential NO_x emissions from the emergency generator are minimal at 7.8 tpy. As such, the cost of add-on control, such as SCR, would not be economically feasible.

Therefore, Consumers believes that if BACT were to be represented by an emission limit, the NSPS regulated limit of 6.4 g/kW-hr would be appropriate for emissions of NO_x.

Carbon Monoxide (CO)

CO emissions result from incomplete combustion of the fuel in the engine's cylinders. Complete combustion relies on adequate mixing of the fuel with the combustion air such that all of the carbon in the fuel is oxidized into carbon dioxide (CO_2). Since this does not occur in even the best combustion systems, the result is emissions of CO. CO is minimized via good engine design that includes the best method of mixing the fuel with the air and providing adequate temperature and residence time for most of the carbon in the fuel to be oxidized into CO_2. Consumers will be using state-of-the-art engine design that will minimize potential CO emissions.

Since the emergency generator will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, CO will be minimized.

Consumers reviewed the RBLC to determine the emissions of CO from similar sized emergency generators for determining BACT. Table 5-16 summarizes the RBLC findings.

Table 5-16. Summary of CO BACT Limits for Emergency Generators > 1,000 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	2,168 hp	12.24 pph	2.56	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	2,220 hp	41.6 pph	8.5	NA	Good combustion practices
Genova OK I Power Plant	OK	750 kW	0.31 lb/MMBtu	0.98	500 hr/yr	Good combustion practices
Port Washington Generating Station	WI	7.6 MMBtu/hr (~1,100 hp)	18.85 pph	7.77	NA	Good combustion practices
Redbud Power Plant	OK	1,818 hp	0.055 lb/hp-hr	24.9	NA	Good combustion practices
Horseshoe Energy Project	OK	1,000 hp	0.85 lb/MMBtu	2.7	NA	Good combustion practices
Mansfield Mill	LA	1,100 hp	10.6 pph	4.37	NA	Preventive maintenance
Cardinal Glass Plant	OK	2,000 kW (~2,682 hp)	0.202 lb/MMBtu	0.64	500 hr/yr	NA
AEP Waterford Energy, LLC	OH	1,000 kW (~1,341 hp)	0.22 tpy	0.30	500 hr/yr	NA

A review of the RBLC indicates that emergency generators have not been required to install additional CO controls because of intermittent operation. The CO ranges between 0.30 g/hp-hr to 24.9 g/hp hr. The NSPS specifies a limit for CO as 3.5 g/kW-hr, which is equivalent to 2.6 g/hp-hr. Except for the Genova OK I Power Plant , Cardinal Glass Plant and AEP Waterford entries, the engines identified in Table 5-16 are greater than the NSPS limit of 2.6 g/hp-hr. None of the engines listed required add-on control but relied on good combustion practices for BACT. Add-on control would not be cost effective due to the minimal CO emissions (4.3 tpy).

Therefore, Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 3.5 g/kW-hr would be appropriate for emissions of CO.

Volatile Organic Compounds (VOC)

VOC emissions result from incomplete combustion of the fuel in the engine's cylinders. Complete combustion relies on adequate mixing of the fuel with the combustion air such that all of the carbon in the fuel is oxidized into carbon dioxide (CO_2). Since this does not occur in even the best combustion systems, the result is emissions of unburned hydrocarbons, expressed in regulations as non-methane hydrocarbons (NMHC) and as VOC. While NMHC and VOC may be technically different they behave in a similar manner, so for the purposes of this BACT analysis they are considered equivalent. VOC is minimized via good engine design that includes the best method of mixing the fuel with the air and providing adequate temperature and residence time for most of the carbon in the fuel to be oxidized into CO_2. Consumers will be using state-of-the-art engine design that will minimize potential VOC emissions.

Since the emergency generator will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, VOC (NMHC) will be minimized.

Consumers reviewed the RBLC to determine the emissions of VOC from similar sized emergency generators for determining BACT. Table 5-17 summarizes the RBLC findings.

Table 5-17. Summary of VOC BACT Limits for Emergency Generators > 1,000 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Horseshoe Energy Project	OK	1,000 hp	0.09 lb/MMBtu	0.29	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	2,220 hp	4.89 pph	1.0	NA	Good combustion practices
Creole Trail LNG Import Terminal	LA	2,168 hp	0.0007 lb/hp-hr	1.01	500 hr/yr	Good combustion practices
Redbud Power Plant	OK	1,818 hp	1.67 pph	0.42	NA	Good combustion practices
Mansfield Mill	LA	1,100 hp	2.7 pph	1.11	NA	Preventive maintenance

A review of the RBLC indicates that emergency generators have not been required to install additional VOC controls because of intermittent operation. The VOC ranges between 0.29 g/hp-hr to 1.11 g/hp hr.

The NSPS specifies a combined limit of NMHC and NO_x of 4.3 g/hp-hr. The combination of emission limits for NO_x and NMHC for the same source is shown in Table 5-18:

Table 5-18. Summary of NOx + NMHC limits for Emergency Generators 1,000 hp

Facility Name	State	Size	Combined NOx/NMHC Limit Equivalent (g/hp-hr)
Horseshoe Energy Project	OK	1,000 hp	15.7
Sabine Pass LNG Terminal	LA	2,220 hp	7.9
Creole Trail LNG Import Terminal	LA	2,168 hp	11.9
Redbud Power Plant	OK	1,818 hp	8.4
Mansfield Mill	LA	1,100 hp	15.1

The NSPS limit is more stringent than any of the combined limits in the RBLC listed sources.

Therefore, Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 4.3 g/hp-hr would be appropriate for emissions of NMHC and NOx.

5.5 FIRE PUMP AND WET FGD QUENCH PUMP ENGINES

The safe operation of the proposed new ASCPC boiler will require that Consumers install other, small compression ignition engines to drive miscellaneous pumps in the event of fire, power loss, or other system failure. A main fire pump, rated at 525 hp, will be used in the event of fire. The wet FGD quench pump will be rated at 455 hp and used only for emergency situations whenever the primary system is down and the hot exhaust gases need to be cooled for protecting FGD equipment. Both emergency engines will be fueled with ultra low sulfur (0.0015% sulfur) diesel fuel.

The fire pump and wet FGD emergency engines will be subject to NSPS Subpart IIII for new non-road compression ignition engines which establishes emission limits for NMHC + NO_x, CO, and PM. USEPA’s AP-42 Ch. 3.3 document is used to estimate potential PM_{10} emissions in lieu of any other available data. The PM_{10} limit of 0.31 lb/MMBtu, listed in Ch. 3.3, is used to calculate total PM_{10} emissions from the emergency engines. Potential emissions are listed in Table 3-16 of Section 3.

The BACT analysis listed in Section 5.4 above also applies to the fire pump and wet FGD pump engines. As such, proper operation and maintenance of the engines pursuant to the manufacturer’s procedures, the use of ultra low sulfur diesel fuel and limiting the hours of operation to not more than 500 hours per year for each engine is considered BACT for this equipment.

The pollutant-specific analysis is discussed in further detail below.

Particulate Matter (PM/PM_{10})

Consumers reviewed the RBLC to determine the emissions of PM/PM_{10} from similar sized emergency engines for determining BACT. All of the PM/PM_{10} is identified as filterable particulate in the RBLC for the engines. Table 5-19 summarizes the RBLC findings.

Table 5-19. Summary of PM/PM$_{10}$ BACT Limits for Emergency Engines ~500 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	660 hp	0.61 pph	0.42	NA	Good combustion practices; low sulfur fuel
Creole Trail LNG Import Terminal	LA	525 hp	0.28 pph	0.24	NA	Good combustion practices; low sulfur fuel
Sabine Pass LNG Terminal	LA	660 hp	1.24 pph	0.85	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	300 hp	0.06 pph	0.09	NA	Good combustion practices
AEP Waterford Energy, LLC	OH	290 kW (389 hp)	0.017 tpy	0.08	500 hr/yr	NA
Mansfield Mill	LA	413 hp	0.9 pph	0.99	NA	Preventive maintenance
Mansfield Mill	LA	587 hp	1.3 pph	1.0	NA	Preventive maintenance
Power System Associates	CA	536 hp	0.15 g/hp-hr	0.15	199 hr/yr	NA
Badger Generating Co, LLC	WI	3.8 MMBtu/hr (543 hp)	0.38 pph	0.32	NA	Good combustion practices; 0.05% wt. sulfur fuel

A review of the RBLC indicates that emergency pump engines have not been required to install additional PM controls because of intermittent operation. The PM/PM$_{10}$ ranges between 0.08 g/hp-hr to 1.0 g/hp hr. The NSPS limit for a similar sized emergency engine is 0.20g/kW-hr, which is equivalent to 0.15 g/hp-hr. Except for the Sabine Pass LNG Terminal and AEP Waterford, the engines identified in Table 5-19 with an equivalent engine rating to the proposed emergency engines are greater than the NSPS limit of 0.15 g/hp-hr.

Therefore, Consumers believes that if BACT were to be represented by an emission limit, the NSPS regulated limit of 0.20 g/kW-hr (0.15 g/hp-hr) represents BACT for emissions of PM/PM$_{10}$.

Sulfur Dioxide (SO_2)

A review of the RBLC indicates that no add on controls are required and that BACT is the use of low sulfur diesel fuel.

Table 5-20. Summary of SO_2 BACT Limits for Emergency Engines ~500 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Redbud Power Plant	OK	300 hp	0.4 lb/MMBtu	1.27	NA	Low sulfur fuel
WPS Weston Plant	WI	460 hp	0.94 pph	0.93	NA	0.003 Wt. % S Fuel Oil
Mansfield Mill	LA	310 hp	0.63 pph	0.92	NA	Low sulfur fuel
Mansfield Mill	LA	775 hp	1.6 pph	0.94	NA	Preventive maintenance
Mansfield Mill	LA	413 hp	0.84 pph	0.92	NA	Preventive maintenance
Mansfield Mill	LA	587 hp	1.2 pph	0.93	NA	Preventive maintenance
Badger Generating Co, LLC	WI	3.8 MMBtu/hr (~543 hp)	1.1 pph	0.92	NA	0.05% wt sulfur fuel

As shown, the use of ultra low sulfur diesel fuel with a sulfur content of 15 ppm (0.0015 percent by weight), which is equivalent to 0.005 g/hp-hr, is more stringent than any other source in the RBLC and represents BACT for the proposed emergency engines.

Oxides of Nitrogen (NO_x)

Since the emergency engines will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer’s recommendations, NO_x will be minimized.

Consumers has reviewed the RBLC to determine the emissions of NO_x from similar sized emergency engines. Table 5-21 summarizes the RBLC findings:

Table 5-21. Summary of NO_x BACT Limits for Emergency Engines ~500 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	660 hp	10.07 pph	6.92	NA	Good combustion practices
Creole Trail LNG Import Terminal	LA	525 hp	6.74 pph	5.82	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	660 hp	12.2 pph	8.38	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	300 hp	3.44 pph	5.20	NA	Good combustion practices
AEP Waterford Energy, LLC	OH	290 kW (389 hp)	0.24 tpy	1.12	500 hr/yr	NA
ADM Corn Processing – Cedar Rapids	IA	540 hp	2.8 g/hp-hr	2.8	3-hr average	NA
Mansfield Mill	LA	413 hp	12.7 pph	13.95	NA	Preventive maintenance
Mansfield Mill	LA	587 hp	18.1 pph	13.99	NA	Preventive maintenance
Badger Generating Co, LLC	WI	3.8 MMBtu/hr (543 hp)	16.76 pph	14.0	NA	Good combustion practices

The NO_x ranges between 1.12 g/hp-hr to 14.0 g/hp- hr. The NSPS specifies a limit for the combined NMHC + NO_x as 4.0 g/kW-hr which is equivalent to 3.0 g/hp-hr. Only the ADM Corn Processing engine and AEP Waterford engine are less than the NSPS limit for total NO_x and NMHC. None of the engines identified in Table 5-21 with an equivalent engine rating to the proposed emergency engines require add-on control equipment.

Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 4.0 g/kW-hr (3.0 g/hp-hr) would be appropriate for emissions of NO_x.

Carbon Monoxide (CO)

Since the emergency engines will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, CO will be minimized.

Consumers reviewed the RBLC to determine the emissions of CO from similar sized emergency engines for determining BACT. Table 5-22 summarizes the RBLC findings.

Table 5-22. Summary of CO BACT Limits for Emergency Engines ~500 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	660 hp	0.3 pph	0.21	NA	Good combustion practices
Creole Trail LNG Import Terminal	LA	525 hp	1.6 pph	1.38	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	660 hp	0.55 pph	0.38	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	300 hp	0.18 pph	0.27	NA	Good combustion practices
ADM Corn Processing – Cedar Rapids	IA	540 hp	2.6 g/hp-hr	2.6	3-hr average	NA
Mansfield Mill	LA	413 hp	2.8 pph	3.08	NA	Preventive maintenance
Mansfield Mill	LA	587 hp	3.9 pph	3.01	NA	Preventive maintenance
Badger Generating Co, LLC	WI	3.8 MMBtu/hr (543 hp)	3.61 pph	3.02	NA	Good combustion practices

A review of the RBLC indicates that emergency engines have not been required to install additional CO controls because of intermittent operation. The CO ranges between 0.21 g/hp-hr to 3.08 g/hp- hr. The NSPS specifies a limit for CO as 3.5 g/kW-hr, which is equivalent to 2.6 g/hp-hr. Except for the Creole Trail LNG Import Terminal and Sabine Pass LNG Terminal, the engines identified in Table 5-22 with an equivalent engine rating to the proposed emergency engines are greater than the NSPS limit.

Therefore, Consumers believes that if BACT were to be represented by an emission limit the limit would be 3.5 g/kW-hr (2.6 g/hp-hr) for emissions of CO.

Volatile Organic Compounds (VOC)

Since the emergency fire pump and FGD pump engines will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, VOC (NMHC) will be minimized.

Consumers has reviewed the RBLC to determine the emissions of VOC from similar sized emergency engines for determining BACT. Table 5-23 summarizes the RBLC findings.

Table 5-23. Summary of VOC BACT Limits for Emergency Engines ~500 hp

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Creole Trail LNG Import Terminal	LA	660 hp	0.04 pph	0.027	NA	Good combustion practices
Redbud Power	OK	300 hp	0.0025 lb/hp-hr	1.13	NA	Good combustion practices
Sabine Pass LNG Terminal	LA	300 hp	0.1 pph	0.15	NA	Good combustion practices
ADM Corn Processing – Cedar Rapids	IA	540 hp	0.2 g/hp-hr	0.2	3-hr average	NA
Mansfield Mill	LA	775 hp	1.9 pph	1.11	NA	Preventive maintenance
Mansfield Mill	LA	413 hp	1 pph	1.10	NA	Preventive maintenance
Mansfield Mill	LA	310 hp	0.76 pph	1.11	NA	Preventive maintenance
Port Washington	WI	7.6 MMBtu.hr	2.15 pph	0.90	NA	Good combustion practices
Badger Generating Co, LLC	WI	3.8 MMBtu/hr	1.37 pph	1.15	NA	Good combustion practices

A review of the RBLC indicates that emergency generators have not been required to install additional VOC controls because of intermittent operation. The VOC limits range between 0.027 g/hp-hr to 1.15 g/hp hr.

The NSPS specifies a combined limit of NMHC and NO_x of 4.0 g/kW-hr, which is equivalent to 3.0 g/hp-hr. The combination of emission limits for NO_x and NMHC for the same sources is shown in Table 5-24:

Table 5-24. Summary of NOx + NMHC limits for Emergency Engines ~500 hp

Facility Name	State	Size	Combined NOx/NMHC Limit Equivalent (g/hp-hr)
Creole Trail LNG Import Terminal	LA	660 hp	6.95
Redbud Power	OK	300 hp	15.2
Sabine Pass LNG Terminal	LA	300 hp	5.35
ADM Corn Processing – Cedar Rapids	IA	540 hp	3.0
Mansfield Mill	LA	775 hp	23.7
Mansfield Mill	LA	413 hp	15.1
Mansfield Mill	LA	310 hp	15.1
Port Washington	WI	7.6 MMBtu.hr	12.3
Badger Generating Co, LLC	WI	3.8 MMBtu/hr	15.2

A review of the RBLC indicates that emergency engines have not been required to install additional NO_x/NMHC controls because of intermittent operation. The NSPS limit is more stringent than any of the combined limits in the RBLC listed sources (with the exception of ADM Corn Processing which is equivalent to the NSPS limit).

Therefore, Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 4.0 g/kW-hr (3.0 g/hp-hr) would be appropriate for emissions of NMHC and NOx.

5.6 FIRE BOOSTER PUMP ENGINE

Consumers is also proposing to install a fire booster pump, rated at 60 hp to be used in the event of fire. Like the other emergency diesel engines, the fire booster pump engine will be fueled with ultra low sulfur (0.0015% sulfur) diesel fuel.

The fire booster pump emergency engine will be subject to NSPS Subpart IIII for new non-road compression ignition engines which establishes emission limits for NMHC + NO_x, CO, and PM. USEPA’s AP-42 Ch. 3.3 document is used to estimate potential PM_{10} emissions in lieu of any other available data. The PM_{10} limit of 0.31 lb/MMBtu, listed in Ch. 3.3, is used to calculate total PM_{10} emissions from the emergency fire booster pump. Potential missions are listed in Table 3-16 of Section 3.

The BACT analysis listed in Section 5.4 above also applies to the fire booster pump engine. As such, proper operation and maintenance of the engines pursuant to the manufacturer’s procedures, the use of ultra low sulfur diesel fuel and limiting the hours of operation to not more than 500 hours per year for the engine is considered BACT.

The pollutant-specific analysis is discussed in further detail below.

Particulate Matter (PM/PM_{10})

Since the emergency fire pump booster will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer’s recommendations, PM/PM_{10} will be minimized.

Consumers reviewed the RBLC to determine the emissions of PM/PM_{10} from similar sized emergency engines for determining BACT. All of the PM/PM_{10} is identified as filterable particulate in the RBLC for the engines. Table 5-25 summarizes the RBLC findings.

Table 5-25. Summary of PM/PM_{10} BACT Limits for Emergency Engines of the Same Size [1]

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Maidsville	WV	85 hp	0.56 pph	3.0	500 hr/yr	NA
Genova OK I Power Project	OK	200 HP	0.031 lb/MMBtu	0.98	NA	Engine design; good combustion
Horseshoe Energy Project	OK	250 HP	0.31 lb/MMBtu	0.98	NA	Low ash fuel
Mansfield Mill	LA	152 HP	0.33 pph	0.98	NA	Preventive maintenance

[1] The RBLC does not list many engines with a horsepower rating in the range of 60 hp. Therefore, the engine sizes shown in this table were chosen for comparison purposes.

A review of the RBLC indicates that good combustion control and/or good engine design is the most stringent requirement for emergency fire booster engine. None of the engines used add on controls to achieve their emission limits. The PM/PM_{10} ranges between a low of 0.98 g/hp-hr to a high of 3.0 g/hp hr. The NSPS limit for the emergency fire pump booster is 0.40 g/kW-hr, which is equivalent to 0.30 g/hp-hr. All of the engines identified in Table 5-25 have higher limits than the NSPS limit. Taking into account the condensable portion, AP-42 Chapter 3.3 was reviewed. Chapter 3.3 does not contain information on the relative amount of condensable emissions from these smaller engines. Nevertheless, the emission factor of 0.31 lb/MMBtu, was conservatively used to represent PM_{10}.

Consumers believes that if BACT were to be represented by an emission limit the limit would be 0.30 g/hp-hr for PM and 0.31 lb/MMBtu for emissions of PM_{10}.

Sulfur Dioxide (SO_2)

A review of the RBLC indicates that no add on controls are required and that BACT is the use of low sulfur diesel fuel.

Table 5-26. Summary of PM/PM_{10} BACT Limits for Small Emergency Engines [1]

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Maidsville	WV	85 hp	3.3 pph	17.6	500 hr/yr	NA
WPS Weston Plant	WI	265 hp	0.54 pph	0.92		Good combustion practices; 0.003% sulfur in fuel
Horseshoe Energy Project	OK	250 hp	0.05 lb/MMBtu	0.16	NA	Low Sulfur Diesel Fuel
Mansfield Mill	LA	265 hp	0.54 lb/hr	0.92	NA	Preventive maintenance
Mansfield Mill	LA	152	0.31 pph	0.93		Preventive maintenance

[1] The RBLC does not list many engines with a horsepower rating in the range of 60 hp. Therefore, the engine sizes shown in this table were chosen for comparison purposes.

As shown, the use of ultra low sulfur diesel fuel with a sulfur content of 15 ppm (0.0015 percent by weight), which is equivalent to 0.005 g/hp-hr, is more stringent than any other source in the RBLC and represents BACT for the proposed emergency fire booster pump.

Oxides of Nitrogen (NO_x)

Since the emergency engines will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, NO_x will be minimized.

Consumers has reviewed the RBLC to determine the emissions of NO_x from similar sized emergency engines for determining BACT. Table 5-27 summarizes the RBLC findings.

Table 5-27. Summary of NO_x BACT Limits for Small Emergency Engines [1]

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Maidsville	WV	85 hp	10.5 pph	56.1	500 hr/yr	NA
Sabine Pass LNG Terminal	LA	300 hp	3.44 pph	5.20	NA	Good combustion practices

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Genova OK I Power Project	OK	200 hp	4.41 lb/MMBtu	14.0	NA	Good combustion practices
Kamichi Energy Facility	OK	270 hp	29.8 lb/MMBtu	94.6	NA	Good combustion practices
WPS – Weston Plant	WI	265 hp	8.21 pph	14.1	200 hr/12 months	Good combustion practices
Horseshoe Energy Project	OK	250 hp	4.41 lb/MMBtu	14.0	NA	Good combustion practices
Mansfield Mill	LA	265 hp	8.2 pph	14.0	NA	Preventive maintenance
Mansfield Mill	LA	152 hp	4.7 pph	14.0	NA	Preventive maintenance

[1] The RBLC does not list many engines with a horsepower rating in the range of 60 HP. Therefore, the engine sizes shown in this table were chosen for comparison purposes.

A review of the RBLC indicates that emergency engines have not been required to install additional NO_X controls because of intermittent operation. The NO_x ranges between 5.20 g/hp-hr to 94.6 g/hp hr. The NSPS specifies a limit for NMHC + NO_x as 7.5 g/kW-hr, which is equivalent to 5.60 g/hp-hr. Except for the Sabine Pass LNG Terminal entry, the engines identified in Table 5-27 with an equivalent engine rating to the proposed emergency engine are greater than the NSPS limit of 7.5 g/kW-hr.

Therefore, Consumers believes that if BACT were to be represented by an emission limit, the NSPS regulated limit of 7.5 g/kW-hr would be appropriate for emissions of NO_x + NMHC.

Carbon Monoxide (CO)

Since the emergency engines will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer’s recommendations, CO will be minimized.

Consumers has reviewed the RBLC to determine the emissions of CO from similar sized emergency engines for determining BACT. Table 5-28 summarizes the RBLC findings.

Table 5-28. Summary of CO BACT Limits for Small Emergency Engines [1]

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Maidsville	WV	85 hp	4.43 pph	23.7	500 hr/yr	NA
Sabine Pass LNG Terminal	LA	300 HP	0.18 pph	0.27	NA	Good combustion practices
Genova OK I Power Project	OK	200 HP	0.95 lb/MMBtu	3.02	NA	Good combustion practices
WPS – Weston Plant	WI	265 HP	1.77 pph	3.03	200 hr/12 months	Good combustion practices
Horseshoe Energy Project	OK	250 HP	0.95 lb/MMBtu	3.02	NA	Good combustion practices
Mansfield Mill	LA	265 HP	1.8 pph	3.08	NA	Preventive maintenance
Mansfield Mill	LA	152 HP	1 pph	2.98	NA	Preventive maintenance

[1] The RBLC does not list many engines with a horsepower rating in the range of 60 HP. Therefore, the engine sizes shown in Table 5-9 were chosen for comparison purposes.

A review of the RBLC indicates that emergency engines have not been required to install additional CO controls because of intermittent operation. The CO ranges between 0.27 g/hp-hr to 23.7 g/hp hr. The NSPS specifies a limit for CO as 5.0 g/kW-hr, which is equivalent to 3.08 g/hp-hr. All of the engines identified in Table 5-28 are less than the NSPS limit of 5.0 g/kW-hr. However, all of these engines are rated at a higher horsepower than the fire pump booster that is rated at 60 hp, and so these larger engines would be expected to operate more efficiently and have a lower emission limit. Note that the Maidsville engine, which is much closer in size to the proposed fire booster pump engine, has a CO limit significantly above the larger engines.

Therefore, Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 5.0 g/hp-hr would be appropriate for emissions of CO.

Volatile Organic Compounds (VOC)

Since the emergency fire booster pump engine will be designed to meet the NSPS requirements in Subpart IIII, and will be maintained in accordance with the engine manufacturer's recommendations, VOC (NMHC) will be minimized.

Consumers reviewed the RBLC to determine the emissions of VOC from similar sized emergency generators for determining BACT. Table 5-29 summarizes the RBLC findings.

Table 5-29. Summary of VOC BACT Limits for Small Emergency Engines [1]

Facility Name	State	Size	Limit	Equivalent (g/hp-hr)	Averaging Period	Control Technology
Maidsville	WV	85 hp	0.64 pph	3.4	500 hr/yr	NA
Kiamichi Energy Facility	OK	270 hp	0.36 lb/MMBtu	1.14	200 hr/12 months	Good combustion practices
Horseshoe Energy Project	OK	250 hp	0.35 lb/MMBtu	1.11	NA	Good combustion practices
Mansfield Mill	LA	265 hp	0.65 pph	1.11	NA	Preventive maintenance

A review of the RBLC indicates that emergency engines have not been required to install additional VOC controls because of intermittent operation. The VOC ranges between 1.1 g/hp-hr to 3.4 g/hp hr.

The NSPS specifies a combined limit of NMHC and NO_x of 4.7 g/kW-hr, which is equivalent to 3.5 g/bhp-hr. The combination of emission limits for NO_x and NMHC for the same source is shown in Table 5-30:

Table 5-30. Summary of NOx + NMHC Limits for Small Emergency Engines

Facility Name	State	Size	Combined NOx/NMHC Limit Equivalent (g/hp-hr)
Maidsville	WV	85 hp	59.5
Kiamichi Energy Facility	OK	270 hp	95.7
Horseshoe Energy Project	OK	250 hp	16.1
Mansfield Mill	LA	265 hp	15.1

The NSPS limit is more stringent than any of the combined limits in the RBLC listed sources. Therefore, Consumers believes that if BACT were to be represented by an emission limit the NSPS regulated limit of 4.7 g/kW-hr would be appropriate for emissions of NMHC and NO_x.

5.7 COOLING TOWERS

Particulate matter can form as a result of nucleation of water on small particles, or impurities, contained in the air stream from the cooling towers. These droplets of particulate and water are referred to as drift when emitted from cooling towers.

The best, and only, technology available to control the emissions of particles, or drift, from cooling towers is drift eliminators. Drift eliminators operate as a blocking mechanism to minimize the amount of water droplets that exit with the air stream. In a very generic sense, a drift eliminator is a solid surface that causes the exiting water droplets to lose velocity and drain back into the cooling tower collection basin. Since the moisture and water droplets are minimized, so are the particulate emissions.

5.8 MATERIAL HANDLING (REVISED FEBRUARY 21, 2008)

A new material handling system will be installed to facilitate the delivery, on-site movement, and handling of fuel, lime, limestone, and other raw materials necessary to operate the ASCPC boiler and associated ancillary equipment, including the air quality control system. The ASCPC material handling and storage systems, including coal, fly ash, limestone, and byproducts associated with the proposed ASCPC boiler, will generate fugitive and non-fugitive PM/PM_{10} emissions.

Fugitive emissions are emissions that are not emitted through a stack, chimney, vent, or other functionally equivalent opening. By the same reasoning, non-fugitive emissions are those that are captured and vented through a control device or stack. By enclosing a material handling or storage operation it is converted from a fugitive source into a non-fugitive source. Fugitive and non-fugitive PM/PM_{10} emissions from material handling will be generated from three general source categories: transfer points, storage buildings/silos and piles, and roads.

5.8.1 Non-Fugitive Emissions

Non-fugitive emissions can be either totally or partially enclosed. Most of these non-fugitive sources are actually fugitive dust emission sources that are being controlled through the use of an enclosure. These enclosures are being further evaluated to identify whether or not it is reasonable to add additional control beyond the enclosure itself. For example, the daily active coal pile for rail unloading is subject to emissions from the conveyors (as a drop), wind erosion, and emissions from reclamation. These activities are being controlled through the use of a total enclosure (i.e., the Coal Barn). To reiterate this point, the Coal Barn itself represents the control technology for minimizing emissions from the daily active pile. While the original submittal indicated fabric filters would be used to control the Coal Barn, further evaluation, as presented in section 5.8.1.4, has shown that it is not economically feasible to do so.

Storage silos and enclosed material handling sources, which represent non-fugitive emissions, associated with ASCPC include:

- Coal Dumper House, Rail Unloading
- Coal Barn
- Transfer towers TTK5-1,2
- Crusher house
- Coal Day Silos, ASCPC Tripper room
- Fly Ash Silo
- Hydrated Lime Silo
- PAC Silo
- Limestone Unloader Bin (Ship unloading)
- Limestone Dome
- Transfer towers TTLS5-1, 2 & 3
- Limestone Reagent Preparation Building

5.8.1.1 Possible Control Technologies

PM/PM$_{10}$ emissions are created as a result of the fines content of the solid material being exposed to the wind or an air current. The higher the fines or silt content the greater the potential for the dust to become airborne. PRB coal typically contains more fines (has a higher silt content) and has a lower surface moisture content than Eastern bituminous coal.

Control options for non-fugitive material handling emissions are those that either lower the PM/PM$_{10}$ generation rate or capture the airborne dust prior to release. Those that lower the generation rate include the application of dust palliatives (water or surfactants) to bind the fines to the large material, or to suppress emissions through direct contact between the spray droplets and the airborne dust.

Fabric filters are the highest efficiency add-on control device for capturing the airborne dust prior to release.

5.8.1.2 Eliminate Technically Infeasible Options

Material conditioning is a technically feasible option, except for situations that would adversely impact the material or the material handling system. For example, adding water during wintertime temperatures at outdoor locations is not feasible due to freezing.

Fabric filters are technically feasible to control PM/PM_{10} emissions whenever the process can be enclosed, or the dust can be captured in an air ventilation system and passed though a vent.

5.8.1.3 Ranking of Technically Feasible Options

Fabric filters are extremely effective at reducing PM/PM_{10} emissions when the process is totally enclosed. Fabric filters can achieve control efficiencies of 99% and higher. The application of water to the coal can effectively bind the fines to the surface of the coal. However, water is not a 4-season option in Michigan for outdoor material handling activities.

5.8.1.4 Energy, Environmental, and Economic Impacts of Control Options

A review of the RBLC database and other sources indicate that fabric filters are commonly selected as BACT for sources that are totally enclosed. The energy and environmental impacts associated with the use of the enclosure and fabric filter PM/PM_{10} emission control technologies would not preclude their selection as BACT for most of these sources. However, Consumers has decided to totally enclose more sources than is typically employed at recently permitted coal fired power plants. These include the Limestone Storage Dome and the Coal Barn for the rail unloaded active coal pile. For these two (2) sources, it is not economically feasible to utilize a fabric filter as an additional control due to the adverse energy and economic impacts. As shown in the following table, the enclosures themselves are expected to greatly minimize the emissions from the piles, with less than 1.0 ton per year expected from the two sources combined.

Table 5-31. Annual Emissions from the Enclosed Piles (tpy)

Source	PM_{10} Emissions
Coal Barn	0.10
Limestone Storage Dome	0.02

Furthermore, the cost per ton of particulate removed using additional dust collection greatly exceeds that which is acceptable for BACT. These costs are presented in Table 5-32 while the detailed economic analysis can be found in Appendix D, Table D-6. While the annualized costs typically include operation and maintenance costs as well as other annual costs, Consumers has conservatively assumed there are no annual costs. Instead, the total capital costs required for procuring and installing the fabric filters was annualized based on a 20-year system life and a 7% annual interest rate. Even with this conservative assumption, the cost per ton of particulate removed greatly exceeds those costs acceptable as BACT. The PM emissions removed have been calculations assuming a control efficiency of 99% for the fabric filter, while the annualized costs have been based on USEPA's Air Pollution Control Cost Manual as well as vendor supplied costs.

Table 5-32. Cost Effectiveness of Fabric Filters on Large Storage Facilities

Source	Capital Costs	Annualized Cost [1]	PM_{10} Emissions Removed (tpy)	Cost per Ton Removed
Coal Barn	$22,537,399	$2,127,305	0.10	$21,487,930
Limestone Storage Dome	$8,647,366	$816,225	0.02	$41,223,479

[1] The annualized costs are based on a cost recovery factor of 0.09439 from EPA's Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001) for a 20-year system life and a 7% annual interest rate. Furthermore, the annualized costs are conservatively based on the capital costs alone without any consideration for the expected annual costs such as O&M, electricity usage, administrative charges, taxes, insurance, etc.

5.8.1.5 Proposed BACT Emission Limit/Practices

The proposed PM_{10} BACT limits and work practice standards for all enclosed material handling sources are presented in Table 5-15 along with the dust control method used to achieve the limit, when applicable.

5.8.2 Fugitive Emissions

Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. As noted in the previous section, the new ASCPC project is being designed to minimize the generation and release of fugitive dust. Given the extensive use of fabric filter control systems, the only sources of fugitive emissions will include the following:

- Outdoor Coal piles. These include one (1) 1,000,000 ton long-term storage pile and one (1) 72,000 ton pile which will be used to offload coal from trains should the Coal Barn not be available and to stage coal for building the long term storage pile. Fugitive emissions can be generated from these piles from:
    - Dropping of the coal from the conveyors belt
    - Wind erosion
    - Dozer activity on the coal piles
    - Feeding the outdoor reclaim hoppers.
- Transfers from ash and gypsum storage silos to trucks for transport.
- Truck hauling of ash and sludge for onsite disposal or sales offsite.
- Ship unloading of limestone into receiving hoppers.

5.8.2.1 Possible Control Technologies

Lower emitting processes and practices are those that reduce the generation rate of PM/PM_{10}. These include conditioning of the material before transport, limiting vehicle speeds, minimizing drop heights, paving unpaved roads, sweeping and/or washing pave roads and using dozers to compact long-term storage piles.

Add on controls to prevent the release of fugitive dust include the use of wet suppression consisting of water or surfactant sprays, surface sealants, partial enclosures and road cleaning.

Wet suppression using water and surfactant sprays control the creation of the fugitive dust by binding the fine particles to the surface of the material, or by suppressing emissions through direct contact between the spray droplets and the airborne dust. Surface sealants create a protective layer on the surface of the material and bind the PM/PM_{10}. Partial enclosures control fugitive dust by partially isolating the material from the wind. Examples include engineered chutes with rubber dust curtains on the end of outdoor conveyor drop points to minimize wind exposure.

5.8.2.2 Eliminate Technically Infeasible Options

The technologies identified in Step 1 were evaluated for technical feasibility and are summarized below.

Material conditioning is a technically feasible option for controlling PM/PM_{10} emissions during material handling operations, but only to the extent that the use of the conditioning agent (e.g., addition of water) does not adversely impact the material or the material handling process.

Compaction is a technically feasible method of controlling fugitive dust emissions, but only when applied to the large piles of compactable material (e.g., coal in the long-term reserve storage pile) that are not frequently disturbed.

Minimizing drop heights of the material is a technically feasible control technology. The use of chutes at the discharge end of conveyors at transfer points and luffing of the conveyor are technically feasible ways to minimize drop heights. Using ground level reclaim hoppers where the coal is pushed by a dozer into the receiving hoppers is another technically feasible method of minimizing the generation of PM/PM_{10}.

Limiting the vehicle speeds on unpaved roads is a technically feasible way to minimize the generation of fugitive dust.

The paving of unpaved roads is a technically feasible way to minimize the generation of fugitive dust.

Water and surfactant sprays are technically feasible for all applications to coal except during freezing conditions.

The use of surface sealants is technically feasible when applied to the long-term reserve storage coal pile, where material is not frequently disturbed.

5.8.2.3 Ranking of Technically Feasible Options

The technically feasible methods for the control of PM/PM_{10} emissions from the proposed material handling operations are employed individually and in combination with other technologies to provide the optimum level of control effectiveness.

Water sprays and surface sealants, when employed in combination, are extremely effective at reducing PM/PM_{10} emissions from long-term storage piles. Generally, control efficiencies in excess of 95% can be achieved through the combined use of these technologies. For active outdoor coal piles the only technically feasible option is water sprays during non-winter months and application of a dust suppressant prior to placement on the pile in winter months. Consumers will minimize the use of the outdoor piles by preferentially unloading the coal from the railcars into a coal barn that is totally enclosed. This barn will have the capacity to hold more than 3 unit trains of coal.

Sweeping and/or water washing of the paved roads, along with limiting the vehicle speed can be over 90% effective in reducing potential dust emissions, but 80% control has been conservatively used.

5.8.2.4 Energy, Environmental, and Economic Impacts of Control Options

A review of the RBLC database and other sources indicate that each of the PM/PM_{10} control technologies identified for use at the proposed new plant has been proven to be effective and established as BACT for PM/PM_{10} emissions control in comparable applications at other facilities. In fact the ASCPC design with the use of a totally enclosed coal barn, and half-moon shaped enclosures with raised troughed-belt design coal transfer conveyors go beyond the design found at other comparable facilities. Thus, there are fewer sources associated with the proposed

ASCPC project that have the potential for fugitive emissions. Based upon this and a review of all site specific considerations for the proposed PM/PM_{10} emission control technologies, the energy and environmental impacts associated with the use of the identified PM/PM_{10} emission control technologies would not preclude their selection as BACT.

The use of a total or partial enclosure of the 1,000,000 ton Reserve Storage pile is not economically feasible, would present a fire hazard and would be functionally and operationally restrictive. Consumers is minimizing the use of the outdoor piles by preferentially unloading the coal into a Coal Barn that is totally enclosed.

5.8.2.5 Proposed BACT Emission Limit/Standards

The selected BACT limits and work practice standards for each material handling source at the proposed ASCPC is shown in Table 5-33.

Table 5-33

Selected BACT for PM/PM_{10} Emissions from Material Handling Operations

Emission Unit	BACT
Dumper House, Rail Unloading	Fabric Filter (0.004 gr/SCF)
Transfer Towers, TT K5-1, 2	Fabric Filter (0.004 gr/SCF)
Coal Barn	Enclosure with low velocity air flow
Reserve Stockout Piles, Drop Emissions	Pre-application of water or suppressant, wet suppressant ring, with conveyor luffing to minimize drop height
Bulldozer Activity on the Coal Pile	Water or dust suppressants
Drop Emissions at Underground Hoppers	Partial enclosure, minimum drop height, opening generally covered with coal
Hoppers for Reserve Piles (Loading)	Partial enclosure, minimum drop height
Hopper for Reserve Piles (Transfer to Conveyor)	Fabric Filter (0.004 gr/SCF)
Crusher House, K5	Fabric Filter (0.004 gr/SCF)
Coal Feed, Silo Row	Fabric Filter (0.004 gr/SCF)
Ship Unloading (Limestone)	Partial Enclosure and Wet Suppression Ring
Ship Unloading Transfer Hopper (DC-LS5-1)	Fabric Filter (0.004 gr/SCF)

Emission Unit	BACT
Limestone Dome	The Limestone Dome is the control technology for the limestone storage pile
Limestone Dome Hopper	Fabric Filter (0.004 gr/SCF)
Transfer Tower, TT LS5-1	Fabric Filter (0.004 gr/SCF)
Transfer Tower, TT LS5-2	Fabric Filter (0.004 gr/SCF)
Transfer Tower, TT LS5-3	Fabric Filter (0.004 gr/SCF)
Limestone Reagent Preparation Building	Fabric Filter (0.004 gr/SCF)
Limestone Day Silo	Fabric Filter (0.004 gr/SCF)
New Fly Ash Bin Filter	Fabric Filter (0.004 gr/SCF)
Hydrated Lime Silo	Fabric Filter (0.004 gr/SCF)
PAC Silo	Fabric Filter (0.004 gr/SCF)
Reserve Storage Pile (1,000,000-ton pile)	Compaction, water sprays for entire pile and sealer on inactive areas.
Paved Roads	Will be swept or watered to reduce silt and speed restriction.
Unpaved Roads	Chemical suppressant and speed restriction.
Truck loading of ash/sludge	Flyash will be conditioned with water to 20-25% moisture content as it leaves the storage silos. Chutes will be used to minimize exposure of material to wind.

5.9 BEST AVAILABLE CONTROL TECHNOLOGY FOR TOXICS (T-BACT)

Rule 224 of Michigan's Rules for Air Pollution Control requires a T-BACT analysis for compounds identified TACs, which also include hazardous air pollutants (or HAPs). The majority of the TACs of concern will be emitted in the form of solids (such as metals) and some may be emitted as both a solid and gas.

The T-BACT analysis required under Michigan Rule R336.1224 follow the MDEQ Operational Memorandum No. 20 (Op Memo 20) for BACT determinations. Op Memo 20 identifies four (4) levels of review and closely reflects the intention of USEPA's methodology for performing BACT analyses for PSD purposes. As described below, the procedure takes advantage of BACT determinations that have been made for other similar equipment across the country over the past several years. This allows for a more streamlined analysis by circumventing the rigorous approach set forth in the NSR Workshop Manual.

LEVEL 1

Level 1 is the first step and identifies the most stringent form of control described as the lowest achievable emission rate (LAER). Any proposed BACT analysis that selects to achieve LAER will be accepted without additional review. If LAER is not chosen, the applicant proceeds to a Level 2 analysis.

LEVEL 2

Level 2 identifies the types of control technologies that have been approved as BACT for similar source types nation-wide. Emission limitations accepted as BACT in recent permits throughout the country for similar processes or industries are acceptable unless new technical developments have been made that indicate additional emission reductions can be achieved in practice. In general, approved limits for BACT over the previous 5-year period are reviewed and compared against the proposed BACT limits in the current application.

If the proposed emission limits are less stringent than those accepted as BACT in recent permits or when few recent BACT determinations exist for the process or industry, and new technical developments have not occurred over the preceding 5-years, the BACT evaluation proceeds to Level 3.

LEVEL 3

A Level 3 BACT evaluation involves consideration of controls that have been accepted as BACT in recent permits for similar air emission streams from different processes or industry types. Level 3 also allows consideration, where appropriate, of older BACT determinations. Control technologies or techniques (i.e., materials, methods or equipment) that have not been demonstrated within the process or industry type under review may be evaluated for use if they are shown to be both available and applicable to the process or industry type for which the application is being prepared.

In the case of materials or methods, consideration is given on the basis of their use in manufacturing identical or similar products from identical or similar raw materials. In the case of add-on control equipment, consideration is made on the basis of the physical and chemical characteristics of the pollutant-bearing streams for which the controls have been applied and compared with those from the process or industry type of the proposed source(s). In Level 3, determining whether energy, environmental, or economic impacts are appropriate is primarily based on current and historical determinations.

If the proposed emission limit is less stringent than those accepted for the same process and industry, the BACT evaluation proceeds to Level 4.

LEVEL 4

The Level 4 BACT evaluation involves a detailed, top-down technical and quantitative analysis for all emission reduction options available for the proposed process and equipment. This analysis mirrors USEPA's 5-step, top-down procedure described in Section 5.1.

Following are discussions regarding T-BACT for the various forms (or groupings) of TACs for the proposed ASCPC boiler.

5.9.1 Mercury (Hg)

Emissions of mercury from the proposed ASCPC boiler are subject to both the federal NSPS Subpart Da and Michigan-specific requirements for best available control technology for toxics (T-BACT). MDEQ requirements for T-BACT may or may not be more stringent than the proposed level of control or emission limit published by EPA and a thorough control technology analysis is required for TACs with respect to energy, environmental, and economic impacts.

5.9.1.1 Possible Control Technologies

The only available add-on control technology specifically designated for control of Hg from combustion of coal is injecting powdered activated carbon (PAC) into the flue gas stream upstream of a fabric filter as part of an activated carbon injection (ACI) system. However, this technology has not yet been commercially proven. The PAC can be either halogenated or non-halogenated.

Halogenated PAC consists primarily of activated carbon that has been treated with iodine or bromine to increase the capture efficiency and usefulness of the carbon and decrease the injection rate of the sorbent. In addition, other halogenated sorbents including iodated carbon and chlorinated carbon are currently undergoing research.
Many existing technologies and systems used for control of particulate matter, sulfur dioxide, and oxides of nitrogen have been demonstrated to have significant co-benefits for control of mercury emissions. Specifically, use of FGD, fabric filters and SCR in the air quality control system has been shown to result in Hg reduction co-benefits. In addition, certain grades of coal have been shown to inherently reduce emissions of mercury due to the constituents within the coal. Recent information available from EPA reports indicate that boilers fired with bituminous coals tend to have significantly lower mercury emissions in the flue gas because the presence of chlorine in the coal ash content. Studies have shown that the mercury has an affinity to combine with the chlorine in bituminous coal to form mercuric chlorides that are then captured in the downstream wet FGD systems. So while bituminous coal may have a higher mercury content, mercury reductions by control systems are generally greater because the chlorine content is generally higher.

Existing Controls

Some of the gaseous (vapor) mercury present in the exhaust gas stream will adsorb to fly ash and other particulate and will be removed by the PM control device. In this project, the PM control device will be a fabric filter.

In addition, divalent mercury (Hg^{2+}) compounds have been shown to be reduced through the use of wet FGD devices, especially for plants firing bituminous coals. The reason stems from the presence of chlorine in the coal and the higher concentration of chlorine in bituminous coals.

Finally, use of SCR for control of NO_x has been proven to reduce Hg in the flue gas stream as well since a portion of the elemental mercury is catalytically oxidized to divalent mercury as it passes through the SCR unit. The use of SCR, wet FGD, and fabric filter technologies in field tests has shown that mercury levels can be reduced by 50% – 80%, but any further reduction requires the use of PAC.

Activated Carbon Injection (ACI)

In ACI systems, powdered activated carbon sorbent is injected into the flue gas upstream of the PM control device. Activated carbon is a specially treated carbon that has been exposed to temperatures of 800 – 900ºC. It becomes "activated" such that the carbon is very porous and has a high surface area. The pores allow vapor-phase mercury to adsorb to the carbon, which is then collected in the downstream PM control device.

The performance of activated carbon is related to physical properties including surface area, pore size, and particle size distribution. Mercury capture is increased with increased pore size and surface area. A large drawback to the use of ACI is the "poisoning" of the fly ash and reduced ability to sell the ash to other industries. To minimize the impact on the fly ash, one option is to install a TOXECON system. In this system, PAC is injected downstream of the primary PM collection device, which is used to collect the fly ash, but upstream of a polishing baghouse that vents to the ambient air. The polishing baghouse or Compact Hybrid Particulate Collector (COHPAC), installed downstream of the sorbent injection is specifically designed to capture the mercury contaminated particulate.

Consumers will be utilizing sub-bituminous and bituminous grades of coal with a robust add-on air quality control system consisting of a SCR, hydrated lime injection, wet FGD and fabric filter. EPA has stated in both the preamble to 40 CFR Part 60 Subparts Da and HHHH, and summary to the reconsideration of the CAMR that best demonstrated technology for mercury control firing bituminous coal is a fabric filter, flue gas desulfurization, and, to a lesser extent, selective catalytic reduction. Several test studies have shown that removal efficiencies for Hg of at least 80% are readily achieved through such a configuration. In this instance, the proposed NSPS limit of 20E-6 lb/MWh represents slightly greater than 80% removal when considering a maximum Hg content in coal of 0.012 ppmw on a wet basis.

Therefore, both existing controls and ACI are technically feasible options to install as part of the AQCS for ASCPC. However, it should be noted that while ACI systems are commercially available, vendors currently will not guarantee removal rates for control of Hg emissions of up to

90% since field test data has shown that such a high level of control cannot be sustained on a long-term, consistent basis (i.e., greater than 30 day blocks).

5.9.1.2 Proposed BACT Emission Limit

Consumers will be installing a PAC injection system as part of the AQCS for the ASCPC boiler. The use of ACI technology is considered BACT for control of Hg emissions from coal-fueled power plants. Consumers will also operate the ACI system to achieve an annual reduction in mercury of 90% consistent with the proposed Michigan rule for mercury from utility boilers. Based on the information presented in Section 3 for mercury in coal, this equates to an emission limit of 64.4 lb/year based on an annual average. This is approximately 0.008 lb/GW and is considered T-BACT for this unit.

5.9.2 Other TACs

The other TACs are in the form of solids (particulates), organic gases and inorganic gases. The TACs that are metals will be in the particulate form at the exhaust temperatures and the fabric filter and wet scrubber represents T-BACT for these materials. Organic Gaseous TACs are primarily controlled by good combustion, although the FGD system may further control these emissions.

5.9.2.1 Non-mercury Metallic TACs/HAPs

Most of the non-mercury metallic TACs/HAPs are present in the fly ash, which is emitted as particulate matter. Therefore, the same control techniques that would be used to control the fly ash PM will control the non-mercury metallic TACs/HAPs emissions.

The proposed ASCPC boiler is subject to BACT for PM emissions and a fabric filter will be utilized to control PM emissions from the boiler. Since the non-mercury metallic TACs/HAPs emissions will be emitted as part of the PM emissions, the fabric filter will also control these emissions to the same level as for PM. Therefore, the proposed fabric filter is considered to represent T-BACT for these compounds.

5.9.2.2 Inorganic TACs/HAPs

The primary inorganic TAC/HAP compounds emitted from the proposed ASCPC boiler are acid gases, including H_2SO_4, HF and HCl. A BACT review for H_2SO_4 and HF has already been completed in Section 5.2. The control technologies chosen for control of H_2SO_4 (i.e., wet FGD and hydrated lime injection) will also provide control of HCl emissions and other inorganic compounds that lead to acid gas.

Therefore, the proposed wet FGD and hydrated lime injection systems represent T-BACT for these compounds.

5.9.2.3 Organic TACs/HAPs

Organic TAC/HAP compounds are emitted due to incomplete combustion of the organic matter in the coal. These emissions include alkanes, alkenes, aldehydes, alcohols and POMs. The inherent design and operation of the boiler provides the factors facilitating complete combustion of most of the organic compounds, including extended residence time, consistent temperature in the combustion chamber, and continuous mixture of air and fuel. Therefore, proper design and good combustion practices will minimize the formation of the organic TACs/HAPs and represents T-BACT for these compounds.