Appendix D

Evaluation of Alternative Control Strategies

Report

Evaluation of Alternative Control Strategies

Prepared for

U.S. Bureau of Land Management

Ely Field Office, Nevada

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1.0 Introduction

1.1 Criteria Pollutants

The Clean Air Act requires EPA to set National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. These pollutants, commonly referred to as Criteria Pollutants are as follows:

- Nitrogen dioxide (NO_2)
- Carbon monoxides (CO)
- Sulfur oxides (SO_2)
- Particulate matter less than 10 microns (PM_{10})
- Particulate matter less than 2.5 microns ($PM_{2.5}$)
- Ozone
- Lead

Emission limits and controls of these pollutants are regulated under 40 CFR 52.21 (Prevention of Significant Deterioration) and 40 CFR 60 (New Source Performance Standards).

1.2 Hazardous Air Pollutants

The U.S. Congress amended the Clean Air Act in 1990 (Section 112) to address a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects. These 188 specific pollutants and chemical groups were initially identified as Hazardous Air Pollutants (HAPs) or sometimes referred to as Air Toxics.

For a complete listing of HAPs refer to EPA's Technology Transfer Network, Air Toxics Web Site (http://www.epa.gov/ttn/atw/188polls.html). Common HAPs emitted from a coal fired power plant include organic compounds, acid gases, and trace metals (including mercury).

1.2.1 Organic Compounds

Organic compounds (some of which are classified as HAPs) include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). These compounds may include the following:

- Alkanes
- Benzene
- Polychlorinated
- Dibenzo-p-dioxins
- Alkenes
- Toluene
- Polychlorinated
- Dibenzofurans
- Aldehydes
- Xylene
- Polycyclic organic matter
- Alcohols
- Ethyl benzene
- Polynuclear aromatic hydrocarbons

These pollutants are usually referred to as volatile organic compounds (VOCs) which are precursors of ozone. Emissions of VOCs are largely dependent on combustion controls. Combustion controls include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete and efficient combustion. However, these same control factors can increase NO_x emissions. Conversely, lower NO_x emission rates achieved through flame temperature control can increase VOC and CO emissions.

1.2.2 Acid Gases

When coal is combusted, a fraction of the chlorine and fluorine in the coal is converted to hydrochloric acid (HCL) and hydrogen fluoride (HF). These are known as acid gases and are effectively removed by the FGD system. It should be noted that depending on the design of the FGD system (wet, spray dry, or dry scrubbers), sulphuric acid (H_2SO_4) emission may be increased. While H_2SO_4 is not a HAP, it is a Prevention of Significant Deterioration (PSD) regulated pollutant discussed in the following Section 1.3.

1.2.3 Trace Metals

Once combusted, the trace metals in the coal may be emitted in the exhaust stream. Various classification schemes have been developed to describe this partitioning behavior (source EPA’s AP 42, Fifth Edition, Volume I, Chapter 1.1). These classification schemes generally distinguish among the following:

- Class 1—Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.
- Class 2—Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.
- Class 3—Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 and Class 2 metals is directly related to control of total particulate matter emissions. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.3 Prevention of Significant Deterioration Pollutants

Prevention of Significant Deterioration (PSD) Pollutants and their significance thresholds are defined in 40 CFR 52.21(J) and are shown in Table 1. These pollutants are made up of criteria, hazardous, and other air pollutants.

TABLE 1
PSD Pollutants and Significant Thresholds

Pollutant	Significance Emission Rate (tons per year)
NO_x	40
CO	100
SO_2	40
PM (total suspended particulate)	25
PM_{10}	15
Ozone (of VOC or NO_X)	40
Lead	0.6
Fluorides	3
H_2SO_4	10
H_2S	10
Total reduced sulfur (including H_2S):	10
Reduced sulfur compounds (including H_2S)	10

Facilities that that are being permitted under the PSD rules and have emissions that exceed the threshold in Table 1 are required to conduct a Best Available Control Technology (BACT) analysis as discussed in Section 2.0.

1.4 Greenhouse Gases

Greenhouse gases are components in the atmosphere that contribute to the greenhouse effect (see Appendix M of this FEIS for additional information on greenhouse gases, the greenhouse effect, and climate change). Some greenhouse gases are emitted to the atmosphere through natural processes, while others result from human activities such as burning of fossil fuels. The primary greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone.

No Nevada state regulations or federal regulations limit greenhouse gas emissions or require the addition of control technology on a stationary source such as a power plant.

1.5 Summary of Pollution Control Strategy

A summary of the White Pine Energy Stations pollution control strategy for the PC-fired boilers is shown in Table 2.

TABLE 2
Summary of Pollution Control Strategy

Pollutant	Control Technology
NO_x	Low NO_x burners Overfire air Selective catalytic reduction
CO	Combustion controls
SO_2	Low-sulfur coal, dry scrubber
VOC	Combustion Controls
Fluorides	Dry scrubber and Fabric filter baghouse
H_2SO_4	Low-sulfur coal, dry scrubber, and Fabric filter baghouse
PM_{10} and non-volatile metals	Fabric filter baghouse
Volatile Metals (Hg)	Halogenated activated carbon and Fabric filer baghouse
CO_2	Efficient generation technology Future add-on technologies to be evaluated

It should be noted that in the evaluating pollution control strategy, there may be tradeoffs with environment impacts that need to be taken into account. The lowest air emission rate for one pollutant does not necessarily result in the lowest overall environmental impact. It is possible to produce more of one pollutant while trying to control another. Examples include the potential increase of ammonia emissions when controlling for NO_x or the increase H_2SO_4 when controlling for SO_2. Other environmental tradeoffs could include electrical efficiency and conservation, conservation of water recourses, and the minimization of wastes that are generated in the pollution control process.

2.0 PSD/Best Available Control Technology

As applicable, the control technologies for the pulverized coal (PC)-fired boilers were selected through the BACT analysis that was conducted as a part of White Pine Energy Associates' (WPEA's) PSD air permit application, which was reviewed and approved by the Nevada Division of Environmental Protection-Bureau of Air Pollution Control (NDEP-BAPC).

In brief, the PSD rules require applicants to evaluate all available control alternatives for PSD pollutants that exceed the significance thresholds and select the best available alternative, considering the associated environmental, energy, and economic impacts. WPEA's analysis of the various control alternatives utilized EPA's preferred "top-down" methodology, which is summarized in this subsection.

2.1 BACT Top Down Process

Chapter B of the EPA's *Draft New Source Review Workshop Manual* (EPA's *Draft NSR Manual*) provides a procedure for use in establishing BACT. This procedure includes a five-step "top-down" process for considering all available control technologies from most stringent to least stringent. The most stringent control technology is considered BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations; or energy, environmental or economic impacts, justify elimination of the most stringent technology and selection of a less stringent technology.

A summary of each of the five steps in the top-down process is described in the following text.

2.1.1 Step 1—Identify All Control Technologies

The primary objective of Step 1 is to identify all potentially applicable control options. Potentially applicable control options are those air pollution control technologies, or techniques, with a practical potential for application to the emission unit and regulated pollutant under evaluation. Potentially applicable control options are categorized as lower emitting processes/practices or add-on controls.

Based on the guidelines provided in EPA's *Draft NSR Manual* and summarized above, and utilizing the sources indicated, a comprehensive list of potentially applicable control technology options was developed for each regulated pollutant emitted from each emission unit.

2.1.2 Step 2—Eliminate Technically Infeasible Options

The objective of Step 2 is to refine the list of potentially applicable control technology options developed in Step 1 by evaluating the technical feasibility of each of the control technology options.

In accordance with EPA's *Draft NSR Manual*, control technologies that have been installed and operated successfully on the type of source under review are "demonstrated" and are considered technically feasible (EPA 1990, p. B17). For technologies that have not been demonstrated for a particular source type, EPA's *Draft NSR Manual* states that a technology is considered technically infeasible if it is not available or not applicable. Control technologies that are not available or not applicable are determined to be technically infeasible.

2.1.3 Step 3—Rank Remaining Control Technologies by Control Effectiveness

The ranking of the control options initially involves the establishment of appropriate units of emission performance. For purposes of the BACT analysis, the unit of measure used for the emissions rate of each pollutant from each emission unit was pounds per million British thermal units (lb/MMBtu).

Achievable emissions limits were established for each of the control technology options based on manufacturer's data, engineering estimates, published literature and the experience of other sources. A table was developed to rank the control technology options by their respective emissions performance from lowest to highest emissions level (highest to lowest control effectiveness). Additionally, Step 3 of the analysis also includes a listing of the energy, environmental, and economic impacts associated with each control option.

2.1.4 Step 4—Evaluate Most Effective Controls and Document Results

The purpose of Step 4 is to either confirm the suitability of the top ranked control technology option as BACT, or provide clear justification for a determination that a lower-ranked control technology option is BACT for the case under consideration. In order to establish the suitability of a control technology option, a case-by-case evaluation of the energy, environmental, and economic impacts of the control technology is performed.

The case-by-case determinations consider both beneficial and adverse direct impacts from an energy, environmental, and economic standpoint. In cases where the determination establishes that there are significant energy, environmental, and/or economic issues that would preclude the selection of the evaluated alternative as BACT, the basis for this determination is clearly documented, and the next most effective alternative is similarly evaluated. This process continues until the evaluated alternative is not rejected and is selected as BACT.

2.1.5 Step 5—Most Effective Control not Eliminated Selected as BACT

In Step 5, the highest ranked control technology not eliminated in Step 4 is selected as BACT.

The following sections present a summary of the top-down BACT analysis completed for the PC boilers. The five-step procedure described in above is summarized for each regulated pollutant applicable to the source.

2.2 Organization of This Report

2.2.1 Process of Evaluation

Because this report is intended as a summary of the control alternatives considered (and not an exact copy of WPEA's BACT analysis), the control technology evaluations presented below are organized as follows:

- Control alternatives considered.
- Control alternatives eliminated.
- Control selected. The top technology is selected except as noted. For any pollutant where the economic, environmental, or energy impacts of the top control alternative eliminate the technology from consideration, the relevant impacts are summarized.

2.3 Summary of Control Alternatives Evaluation for CO and VOC

2.3.1 Control Alternatives Considered

Carbon monoxide and VOCs are generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated boilers typically emit low levels of CO/VOC. A listing of potential control alternatives is provided in Table 3.

TABLE 3
Summary of Control Alternatives

Control Alternatives	Description
Combustion Controls	Optimization of the design, operation, and maintenance of the furnace and combustion system is the primary mechanism available for lowering CO/VOC emissions. The furnace/combustion system design on modern PC-fired boilers provides all of the factors required to facilitate complete combustion. As a result, a properly designed furnace/combustion system is effective at limiting CO/VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen.
Flares	Flares are commonly used in the control of organic-laden slipstreams with sufficient heating value. When an exhaust stream is ignited by the pilot flame at the flare tip, combustion occurs in the ambient air above the flare.
Afterburning	Afterburners convert CO/VOC into CO_2 by utilizing simple gas burners to bring the exhaust stream temperature up to 1,400°F to promote complete combustion.
Catalytic Oxidation	A catalytic oxidizer converts the CO/VOC in the combustion gases to CO_2 at temperatures ranging from 500°F to 700°F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst.
External Thermal Oxidation	ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1,400°F to 1,600°F) and oxygen to convert CO/VOC in the flue gas to CO_2.

2.3.2 Control Alternatives Eliminated

The potentially applicable control alternatives for CO/VOC emissions identified are each evaluated for technical feasibility. Alternatives that are not available or not applicable are considered technically infeasible and are eliminated. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 4 lists the technical feasibility evaluation for each control alternative listed in Table 3.

TABLE 4
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Combustion Controls	Combustion controls are a proven technology for the reduction of CO/VOC emissions. Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for PC-fired boiler CO/VOC emissions control.	Yes
Flares	Flares have not been demonstrated for PC-fired boiler CO/VOC emission control. Limitations on the scalability of this technology preclude its commercial availability. Because the PC-fired boiler exhaust will not have sufficient heating value for flaring and because flares have not been applied for PC-fired boiler emissions control, flares are not considered an applicable technology for PC-fired boilers.	No
Afterburning	Afterburners are not demonstrated for PC-fired boiler CO/VOC control. Further, natural gas is not available at this site. The PC boilers will be tuned to maximize fuel combustion while minimizing NO_x formation, the process will result in essentially complete combustion.	No
Catalytic Oxidation	Catalytic oxidation is not a demonstrated technology for PC-fired boilers. Catalytic oxidation systems require a minimum temperature of 500°F for proper operation, dictating that the catalyst be installed upstream of the flue gas desulfurization and fabric filter systems. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of any oxidation catalyst. Trace elements present in the coal and the combustion gases would foul the catalyst, dramatically reducing its effectiveness.	No
External Thermal Oxidation	Regenerative ETO and recuperative ETO have not been demonstrated for use on PC-fired boilers. ETO is not applicable for PC-fired boiler CO/VOC control for the same reason as afterburners.	No

2.3.3 Control Alternative Selected

Based on the analysis summarized above, combustion controls are the top control alternative. Therefore, combustion controls were selected as BACT for CO/VOC. Table 5 lists the BACT emission limits for CO/VOC.

TABLE 5
List of BACT Emission Limits for CO/VOC

Pollutant	Control Alternative Selected	BACT Emission Limit
CO	Combustion Controls	0.15 lb/MMBtu (24-hour average)
VOC	Combustion Controls	0.0036 lb/MMBtu (24-hour average)

2.4 Summary of Control Alternatives Evaluation for NO_x

2.4.1 Control Alternatives Considered

In coal-fired boilers, fuel nitrogen oxides (NO_x) generally accounts for 75 percent of all NO_x generated. Additional NO_x can be generated because of high-temperature reactions between nitrogen and oxygen in the combustion air. Factors affecting the generation of NO_x include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel.

A listing of potential control alternatives is provided in Table 6. Combinations of control alternatives were evaluated where such combinations would potentially apply.

TABLE 6
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Nitrogen is one of the elements contained in coal. The amount of nitrogen varies with the type of coal, but generally ranges from 0.5 to 2 percent (EPA 2002). Presumably, fuel NO_x emissions could be reduced by burning a coal that contains less nitrogen.
Low NO_x Burners (LNB)	LNB are designed to limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the distribution and mixing of the fuel and air.
Overfire Air (OFA)	OFA is a combustion control technology in which 5 percent to 20 percent of the total combustion air is diverted from the burners and injected through ports located above the top burner level (Srivastava, et al. 2005). OFA is generally used in conjunction with Low NO_x Burners which reduces NO_x formation.
Rotating Opposed Fire Air (ROFA)	ROFA® is a new combustion technology developed by Mobotec USA, Inc. The ROFA® design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion.
Induced Flue Gas Recirculation (IFGR)	Induced flue gas recirculation (IFGR) recirculates boiler flue gas from the boiler outlet to the furnace here it is reintroduced into the combustion process.
Selective Catalytic Reduction (SCR)	SCR is a post-combustion NO_x reduction technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_x react on the surface of the catalyst, forming nitrogen (N2) and water.

TABLE 6
Summary of Control Alternatives

Control Alternative	Description
Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)	NGR diverts part of the main fuel heat input to locations above the main burners, thus creating a secondary combustion zone called the reburn zone. A secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel.
Fuel-Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)	FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_x.
Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)	AGR adds a nitrogen rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_x reduction to produce free radicals that enhance the selective non-catalytic NO_x reduction.
Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)	AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich NO_x reduction zones in an overall fuel-lean furnace.
Hybrid Selective Reduction (HSR)	HSR is a combination of selective non-catalytic reduction (SNCR) and SCR that is designed to provide the performance of full SCR with a smaller footprint and potentially lower costs. The final emission level of an HSR system is equivalent to the level of control achieved by an SCR system.
$SCONO_x$	$SCONO_x$ uses a precious metal catalyst to simultaneously convert NO_x and CO to CO_2, H_2O, and N_2. The catalyst must be periodically removed from service for regeneration.
$THERMALONO_x$	$THERMALONO_x$ is based on the oxidation of NO to NO_2 and then dissolving the NO_2 in water. The THERMALONOx technology is intended for use with a wet flue gas desulfurization (FGD) system used for SO_2 emission control.
Electro-Catalytic Oxidation (ECO)	ECO oxidizes gaseous pollutants in a reactor. A scrubber removes NO_x, SO_2 and the oxidizer reactor products. A WESP captures the oxidized pollutants.
Pahlman Process	The Pahlman Process is a multi-pollutant control technology that simultaneously controls NO_x and SO_2. This technology is currently in the pilot stage of development, and the company operates a trailer-mounted pilot demonstration unit that can process coal-fired boiler exhaust slip streams of up to 2,000 scfm (NETL, 2007).

2.4.2 Control Alternatives Eliminated

The potentially applicable technologies for the control of NO_x emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 2.5 lists the technical feasibility evaluation for each control technology listed in Table 7.

TABLE 7
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value; coal is not sorted by nitrogen content or NO_x production potential.	No
Low NO_x Burners (LNB)	LNB are a mature technology for the reduction of NO_x formation during combustion. LNB have been demonstrated in practice and are available from numerous vendors that are willing to offer performance guarantees.	Yes
Overfire Air (OFA)	OFA is a mature technology most often utilized concurrently with the application of LNB. OFA is expected to be furnished with a new boiler regardless of other post-combustion NO_x emission reduction technologies employed. For these reasons, OFA is considered technically feasible.	Yes
Rotating Opposed Fire Air (ROFA®)	To date, ROFA® has only been installed as a retrofit technology on units firing bituminous coals. Additionally, the ROFA® technology would not be expected to provide better emissions performance than the LNB + OFA baseline, ROFA® technology is not considered further in this analysis.	No
Induced Flue Gas Recirculation (IFGR)	IFGR has not been demonstrated as a NO_x reduction technology for PC-fired boilers. IFGR is only commercially available for gas and oil-fired units. The applicability of this technology is precluded because of the technical complications associated with recirculating the volume of hot, ash-laden flue gas that is generated by a large coal-fired boiler.	No
Selective Catalytic Reduction (SCR)	SCR is a proven technology for the reduction of NO_X emissions. It has been demonstrated in similar applications to reduce NO_x emissions significantly over a range of load conditions.	Yes
Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)	NGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the NGR + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing NGR would represent additional capital and operating costs with no assurance of improved environmental performance. (Cost information is provided for NGR to establish the higher cost of the reburning technologies – Since natural gas is not currently available at the site, WPEA would have to construct approximately 90 miles of natural gas pipeline at an estimated capital cost of $73.7 million. Annual costs for natural gas are estimated at $104.9 million. Negative environmental impacts would also be expected due to construction of a 90 + mile natural gas pipeline.)	No
Fuel Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)	FLGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the FLGR + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing FLGR would represent additional capital and operating costs with no assurance of improved environmental performance.	No
Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)	AGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the AGR + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing AGR would represent additional capital and operating costs with no assurance of improved environmental performance.	No

TABLE 7
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)	AEGI could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the AEGI + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing AEGI would represent additional capital and operating costs with no assurance of improved environmental performance.	No
Hybrid Selective Reduction (HSR)	Because HSR involves the sequential application of SNCR and SCR, the final emission level of an HSR system is equivalent to the level of control achieved by an SCR system. WPEA is willing to accept the potentially higher cost of SCR in exchange for the demonstrated reliability of this proven technology.	No
$SCONO_x$	$SCONO_x$ is not a demonstrated technology for controlling NO_X emissions from coal-fired boilers. The manufacturer of this technology does not offer $SCONO_x$ for application to coal-fired boilers. The presence of sulfur in the flue gas has the potential to poison the $SCONO_x$ catalyst, limiting its effectiveness and its useful life.	No
$THERMALONO_X$	The poorer-than-expected results of the first commercial operation prompted the host utility to halt testing of the technology until further laboratory testing could be completed. $THERMALONO_x$ is currently in the laboratory/pilot stage of development.	No
Electro-Catalytic Oxidation (ECO)	The ECO technology is still in the pilot plant stage of development. This technology has not been demonstrated for full-scale operations.	No
Pahlman Process	The Pahlman Process has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available.	No

2.4.3 Control Alternative Selected

LNB + OFA is compatible with SCR. Based on the analysis summarized above, the combination of LNB, OFA, and SCR was determined to be the top control option. Therefore, BACT for NO_x was determined to be the application of LNB, OFA, and SCR with a limit of 0.07 lb/MMBtu on a 24-hour rolling average basis.

2.5 Summary of Control Alternatives Evaluation for SO_2

2.5.1 Control Alternatives Considered

Sulfur Dioxide (SO_2) is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. A listing of potential control technologies is provided in Table 8.

TABLE 8
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Coal-fired boiler SO_2 emissions result from the oxidation of sulfur contained in the coal during the combustion process. Therefore, the potential for SO_2 formation can be reduced by firing coal with low sulfur content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry.
Regenerable Wet Scrubber	The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of sulfur compounds that can be further processed.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and SO_2.
Limestone Injection Dry Scrubbing (LIDS)	In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device.
Furnace Sorbent Injection + Wet Scrubber	FSI/DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb SO_2. In the FSI technology, the reagent is injected directly into the furnace. In the DSI technology, the reagent is injected into the ductwork. The reaction product is collected in the downstream particulate collection device.
Duct Sorbent Injection + Wet Scrubber	

2.5.2 Control Alternatives Eliminated

In this step, the potentially applicable technologies for the control of SO_2 emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 9 lists the technical feasibility evaluation for each control technology listed in Table 8. Because coal selection is a feasible option for all potential add-on control technologies, coal selection was used as the base case for the impact summary.

TABLE 9
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation. Low sulfur PRB, Colorado, and Utah coals are available for use at the Facility.	Yes
Coal Cleaning/Coal Refining	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning. Coal refining is not a demonstrated technology for large-scale PRB coal combustion. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available. Regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a wet scrubber. EPA's Draft NSR Manual allows applicants to review only the lowest cost option if several potential options achieve an essentially identical level of performance (EPA 1990, p. B20).	No
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Limestone Injection Dry Scrubbing (LIDS)	LIDS is not a demonstrated technology for controlling SO_2 emissions from large-scale coal combustion. LIDS is still under development and is not commercially available for large-scale operations.	No
Furnace Sorbent Injection + Wet Scrubber Duct Sorbent Injection + Wet Scrubber	FSI/DSI could presumably be used in conjunction with a wet scrubber. However, the control efficiency of the wet scrubber would decrease because of lower inlet SO_2 concentrations, and there is no data available to indicate that the FSI/DSI + Wet Scrubber combination could achieve a lower SO_2 emission rate than a wet scrubber alone.	No

2.5.3 Impacts Associated with Wet Scrubbing

Although wet scrubbing was determined to have the highest SO_2 control efficiency, the wet scrubbing alternative was eliminated from consideration because of the associated energy, environmental, and economic impacts detailed in WPEA's PSD air permit application and summarized as follows:

1. Of particular importance is that dry scrubbing in combination with a baghouse will result in lower overall air emissions (219 tons per year lower emissions) than wet scrubbing, as shown in Table 10.

2. A wet scrubber would result in higher rates of acid emissions (HF and sulfuric acid mist) compared to a dry scrubber in combination with a baghouse. Higher rates of acid emissions would result in increased rates of acid deposition, potentially affecting terrestrial and aquatic ecosystems.
3. Water consumption for a wet scrubber would be approximately 40 percent higher than required to operate a dry scrubber. A wet scrubber system has an incremental consumption of 678 acre-feet (221,000,000 gallons) of water per year. That additional water would be capable of supporting approximately 841 additional homes (based on the average Nevada household consuming 0.8 acre-foot (262,645 gallons) of water per year) (American Water Works Association, 1996).
4. A wet scrubber would create a wastewater stream estimated to require an additional 42 acres of evaporation pond surface area.
5. A wet scrubber would use more than twice the amount of energy of a dry scrubber. A wet scrubber would demand a parasitic load of up to 34.5 MW for the Facility. This would be enough energy to provide for approximately 29,000 homes (UtiliPoint, 2007).
6. A wet scrubber would produce additional solid waste and would consume additional solid waste disposal space compared to a dry scrubber. The extra 76,018 tons per year produced by a wet scrubbed facility would consume an additional 801 acre-feet of disposal area space.
7. A wet scrubber would be more likely than a dry scrubber to emit a visible steam plume, which is considered an undesirable effect.
8. The estimated incremental cost of wet scrubbing would be in the range of incremental costs contributing to other recent decisions in favor of dry scrubbing. The incremental cost of using wet scrubber over dry would be $20,114 per ton. Based on this annualized cost, the additional cost for wet scrubbing over dry scrubbing would be $33,795,000 per year.

TABLE 10
Facility-Wide Emissions Related to SO_2 Control Options

	Total Emissions from the PC-Fired Boilers [c]	
Pollutant	**Dry Scrubber (tons per year)**	**Wet Scrubber (tons per year)**
SO_2 [a]	4,455	2,742 [b]
H_2SO_4	164	1,124
Fluorides as HF	66	754
Efficiency Related Emissions [d]		
CO	-	134
NO_x	-	62
SO_2	-	36

TABLE 10
Facility-Wide Emissions Related to SO_2 Control Options

Pollutant	Total Emissions from the PC-Fired Boilers [c] Dry Scrubber (tons per year)	Wet Scrubber (tons per year)
PM/PM_{10}	-	34
VOC	-	3
H_2SO_4	-	15
Total	**4,685**	**4,904**

[a] Assumes coal with an average sulfur content of 0.32 percent (the average of 12 PRB coal specifications obtained as the design coal basis for the Plum Point Energy Station in Osceola, Arkansas). For this coal, a dry scrubber would achieve 0.065 lb/MMBtu, and a wet scrubber is assumed to achieve 0.04 lb/MMBtu.

[b] For the emissions comparison, a conservatively low wet scrubber SO_2 emission factor of 0.04 lb/MMBtu is used, corresponding to 95 percent control with 0.32 percent sulfur coal. This low emission factor reflects NDEP's decision on the Newmont permit requiring control efficiency values as enforceable permit limits (if NDEP required 95 percent control for a wet-scrubbed system firing 0.32 percent sulfur coal, the resulting SO_2 emission limit would be 0.04 lb/MMBtu). There are currently no wet scrubber systems with permitted or proposed SO_2 BACT limits less than 0.06 lb/MMBtu. Thus, the concept of achieving 0.04 lb/MMBtu as SO_2 BACT remains speculative and is only presented here to create the most conservative comparison between the two technologies.

[c] Assumes 100 percent annual capacity factor.

[d] Efficiency-related emissions represent the additional emissions associated with having to use more fuel to compensate for the higher parasitic load from wet scrubbing. Dry scrubbing is considered the base case for efficiency related emissions.

2.5.4 Control Alternative Selected

Because wet scrubbing was eliminated from consideration during the BACT analysis because of the energy, environmental, and economic impacts summarized above, wet scrubbing is not carried forward for detailed analysis in the EIS. Dry scrubbing in combination with low sulfur coal was selected as SO_2 BACT for the PC-fired boilers. Because the SO_2 emission rate depends on the sulfur content of the coal combusted, a two-tiered SO_2 BACT limit was created:

- 0.09 lb/MMBtu for coals with greater than or equal to 0.45 percent sulfur and
- 0.065 lb/MMBtu for coals with less than 0.45 percent sulfur

2.6 Summary of Control Alternatives Evaluation for PM/PM_{10} and Lead

2.6.1 Control Alternatives Considered

Particulate matter (PM) is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions that are less than 10 microns in diameter are referred to as PM_{10}. PM and PM_{10} are emitted from coal-fired boilers as a result of the ash contained in the coal. Approximately 80 percent of the ash contained in the coal becomes fly ash and is present in the boiler exhaust as PM and/or PM_{10}. Additionally, lead is typically contained in the particulate matter with size less than 10 microns. Therefore, the control technologies available for the control of PM/ PM_{10} emissions are the same technologies for the control of lead. A listing of potential control alternatives is provided below in Table 2.9.

TABLE 11
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Combustion of a lower ash-containing coal would result in less fly ash, hence less PM/PM_{10}. Additionally, lead emissions could be reduced by burning coals that contain less lead content.
Coal Cleaning	Coal normally contains quantities of inorganic elements, and trace levels of lead. These elements may occur in the ash-forming mineral deposits embedded within the coal. Coal cleaning is a process that removes this mineral ash matter from the coal.
Fabric Filter	A fabric filter baghouse removes particles and condensed metals (including lead) from the flue gas by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. The dust is then collected in a hopper.
Electrostatic Precipitator (ESP)	An electrostatic precipitator (ESP) removes dust and condensed metals (including lead) from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed by a rapping system into a ash hopper.
Wet Electrostatic Precipitator (WESP)	A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP. However, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid.

2.6.2 Control Alternatives Eliminated

In this step, the potentially applicable control alternatives for the control of PM/PM_{10}-lead emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 12 summarizes the technical feasibility evaluation for each control alternative listed in Table 11.

TABLE 12
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by ash content.	No
Coal Cleaning	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning.	No
Fabric Filter Baghouse	The fabric filter baghouse is a proven technology for the control of boiler PM/PM_{10}-lead emissions, and demonstrated in similar applications.	Yes
Electrostatic Precipitator (ESP)	The ESP is a proven technology for the control of boiler PM/ PM_{10}-lead emissions, and has been widely demonstrated in similar applications.	Yes
Wet Electrostatic Precipitator (WESP)	The WESP is a proven technology for the control of boiler PM/ PM_{10}-lead emissions. This technology has been demonstrated in similar applications	Yes

TABLE 12
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?

2.6.3 Control Alternative Selected

Based on vendor data, and recent permitting precedent; an ESP, a WESP, and a fabric filter baghouse would all be expected to achieve the same level of control: 0.015 lb/MMBtu for PM/PM_{10}, and 1.8×10^{-5} for lead. EPA's *Draft NSR Manual* allows applicants to review only the lowest cost option that achieves an identical level of performance (EPA, 1990, B20). An ESP/WESP would present additional cost because of the auxiliary power consumed. The additional power required to operate an ESP/WESP (3.62 MW), as compared to a filter baghouse would be enough energy to provide for approximately 3,042 homes (UtiliPoint, 2007). A WESP would also create a wastewater stream requiring treatment, representing additional costs and environmental impacts. Accordingly, BACT for PM/ PM_{10}-lead emissions control was determined to be the use of a fabric filter baghouse. Because the ESP and WESP alternatives were eliminated during the BACT analysis because of the equivalent level of control and associated environmental and economic impacts, the ESP and WESP alternatives are not carried forward for detailed analysis.

The BACT emissions limit for PM/PM_{10} was established as 0.015 lb/MMBtu on a 3-hour rolling average basis, and the BACT emissions limit for lead was established as 1.8×10^{-5} lb/MMBtu on a 3-hour rolling average basis.

2.7 Summary of Control Alternatives Evaluation for Fluorides

2.7.1 Control Alternatives Considered

Fluorides are emitted from coal-fired boilers because of trace concentrations of elemental fluorine and fluorine compounds in the coal. Fluorine is emitted predominantly in the gaseous form of hydrogen fluoride (HF). For the purposes of this analysis, fluorides are expressed as HF as appropriate because all emissions of fluorides from the PC boilers are expected to be in the form of HF. A summary of potential control alternatives is provided in Table 13.

TABLE 13
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Fluorine exists in trace amounts in coal deposits. Fluoride emissions could be reduced by burning coals that contained less fluorine content.
Coal Cleaning	Fluorine may occur in the ash-forming mineral deposits embedded within the coal. Coal cleaning is a process that removes this mineral ash matter from the coal after it is removed from the ground.

TABLE 13
Summary of Control Alternatives

Control Alternative	Description
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The HF is removed from the flue gas by sorption and reaction with the slurry.
Regenerable Wet Scrubber	The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of sulfur compounds that can be further processed.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and HF.
Furnace Sorbent Injection/ Duct Sorbent Injection	DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb HF. In the FSI technology, the reagent is injected directly into the furnace. In the DSI technology, the reagent is injected into the ductwork. The reaction product is collected in the downstream particulate collection device.

2.7.2 Control Technologies Eliminated

The potentially applicable control alternatives for HF emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 14 lists the technical feasibility evaluation for each control technology listed in Table 13.

TABLE 14
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by fluorine content.	No
Coal Cleaning	Coal cleaning would provide no significant benefit for the added cost and water consumption. Therefore, coal cleaning is not typically performed on PRB, Colorado, or Utah coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	Regenerable wet scrubbers have been installed and operated successfully on PC boilers. Thus, regenerable wet scrubbers are considered technically feasible.	Yes
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes

TABLE 14
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Furnace Sorbent Injection /Duct Sorbent Injection	Although there is little operating experience supporting the effectiveness of FSI/DSI in removing HF from PC-fired boiler exhaust, FSI/DSI is considered technically feasible.	Yes

2.7.3 Control Alternative Selected

Based on EPA data (EPA, 2002), the top control alternative is a dry scrubber with fabric filter baghouse. The top control alternative was selected for HF BACT: the application of a dry scrubber and fabric filter baghouse combination with an emission limit of 9.7×10^{-4} lb/MMBtu on a 3-hour average basis.

2.8 Summary of Control Alternatives Evaluation for H_2SO_4

2.8.1 Control Alternatives Considered

The formation of H_2SO_4 occurs via two primary mechanisms. The first mechanism is the formation of liquid droplets of H_2SO_4 from the reaction of water vapor and SO_3. The second mechanism is through vapor condensation. A listing of potential control alternatives is provided in Table 15.

TABLE 15
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Coal-fired boiler H_2SO_4 emissions result from the oxidation of sulfur contained in the coal during the combustion process. Therefore, the potential for H_2O_4 formation can be reduced by firing coal with low sulfur content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The H_2SO_4 is removed from the flue gas by sorption and reaction with the slurry.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and H_2SO_4.

TABLE 15
Summary of Control Alternatives

Control Alternative	Description
Limestone Injection Dry Scrubbing (LIDS)	In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device.
Furnace Sorbent Injection/ Duct Sorbent Injection + Wet Scrubber	DSI/FSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb H_2SO_4. FSI injects the reagent directly into the furnace. In the DSI technology, the reagent is injected into the ductwork.
Wet Electrostatic Precipitator (WESP)	A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP. However, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid.

2.8.2 Control Alternatives Eliminated

The potentially applicable control alternatives for H_2SO_4 emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 16 lists the technical feasibility evaluation for each control technology listed in Table 15.

TABLE 16
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	Coal selection is a demonstrated method for minimizing the amount of sulfur available for H_2SO_4 formation. Low sulfur PRB, Colorado, and Utah coals are available for use at the Facility.	Yes
Coal Cleaning/ Coal Refining	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available. Regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a wet scrubber. EPA's Draft NSR Manual allows applicants to review only the lowest option if several potential options achieve an essentially identical level of performance (EPA, 1990, B20).	No
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Limestone Injection Dry	LIDS is not a demonstrated technology for controlling H_2SO_4 emissions from large-scale coal combustion. LIDS is still under	No

TABLE 16
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Scrubbing (LIDS)	development and is not commercially available for large-scale operations.	
Furnace Sorbent Injection/ Duct Sorbent Injection	Although there is little operating experience supporting the effectiveness of FSI/DSI in removing H_2SO_4 from PC-fired boiler exhaust, FSI/DSI is considered technically feasible.	Yes
Wet Electrostatic Precipitator (WESP)	WESP systems have been shown to remove H_2SO_4 mist from exhaust streams and are considered technically feasible.	Yes

2.8.3 Impacts Summary

Because WESP technology is compatible with both wet and dry scrubbing, this technology was evaluated in conjunction with both wet and dry scrubbers. The top three control alternatives, in terms of H_2SO_4 removal efficiency, were determined to be the following:

1. Dry Scrubbing + WESP
2. Wet Scrubbing + WESP
3. Dry Scrubbing

Both dry scrubbing and wet scrubbing in combination with WESP were eliminated from consideration because of the associated energy, environmental, and economic impacts detailed in WPEA's PSD air permit application and summarized below.

2.8.3.1 Energy Impacts

Compared to a dry scrubber alone, a WESP would result in a 33 percent higher parasitic load, and the combination of wet scrubbing + WESP would result in a parasitic load over 300 percent higher. To put these parasitic values in perspective, the WPES would have to combust an additional 19,027 tons of coal per year to compensate for auxiliary power consumed by the WESP. For a wet scrubber + WESP, an additional 142,017 tons of coal would be required. This additional fuel consumption would result in additional air emissions and train traffic.

2.8.3.2 Environmental Impacts

Water Consumption—Compared to a dry scrubber alone, a WESP would result in 11 percent higher water usage, and the combination of wet scrubbing + WESP would result in 51 percent higher water usage. This increased water usage equates to enough water to support 224 homes and 1,065 homes respectively.

Wastewater Production—While a dry scrubber alone would not produce a wastewater stream, a wet scrubber would produce a wastewater stream containing concentrations of dissolved and suspended chemicals potentially requiring specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals (which are 15 percent to 25 percent higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547 percent higher for a plant with wet scrubbing than with a plant with dry scrubbing). A WESP would create a blowdown stream that must be chemically neutralized prior to discharge. The neutralized blowdown stream would have to be discharged and treated in accordance with the applicable regulations.

Solid Waste Production—A wet scrubber would produce additional solid waste and would consume an additional solid waste disposal space of 801 acre-feet/year.

Blowdown—A WESP would create a blowdown stream that must be chemically neutralized prior to discharge. The neutralized blowdown stream must then be discharged and treated in accordance with the applicable regulations.

2.8.3.3 Economic Impacts

Compared to a dry scrubber alone, the incremental cost (the cost of achieving the additional emissions reductions) of adding a WESP would be $175,000 per ton of H_2SO_4 removed, and the incremental cost of wet scrubbing + WESP would be $524,000 per ton of H_2SO_4 removed. Annualized, the incremental costs would be $6,956,000 and $18,142,000 respectively.

2.8.3.4 Summary

Based on the negative energy, environmental, and economic impacts summarized above, the dry scrubbing + WESP and wet scrubbing + WESP alternatives were eliminated from further consideration in the BACT analysis. Because the combinations of dry scrubbing + WESP and wet scrubbing + WESP were eliminated during the BACT analysis, these alternatives are not carried forward for detailed analysis. The top remaining control alternative is dry scrubbing.

2.8.4 Control Alternative Selected

Based on the analysis summarized above, dry scrubbing was selected as H_2SO_4 BACT for the PC-fired boilers. Additionally, the selection of low-sulfur coal (as determined above in the analysis for SO_2) will help to minimize emissions of H_2SO_4. The BACT emission limit is 0.0034 lb/MMBtu on a 3-hour average.

3.0 Hazardous Air Pollutants

As discussed in Sections 1.1, HAPs can be divided into several categories, including organic compounds, acid gases, and metals. Many of the control strategies implemented for the PSD Pollutants, discussed in Section 2, have a collateral affect for controlling HAPs. These are discussed below.

Evaluations of the available control alternatives for organic compounds, acid gases, and metals are provided in detail below.

3.1 Summary of Control Alternatives Evaluation for Organic HAPs

Organic HAPs emitted from coal combustion include compounds listed in Section 1.2.1. The control strategies for these pollutants are the same as those utilized for VOCs. For a detailed evaluation of the control alternatives applicable to organic HAPs, please see the evaluation for VOC control alternatives in Section 2.3. Based on evaluation of the feasibility of the available control techniques for VOCs, combustion controls were selected as the preferred control alternative for organic HAPs.

3.2 Summary of Control Alternatives Evaluation for Acid Gases HAPs

Acid gas HAPs emitted from coal combustion include HCl and HF. The control strategies for these pollutants are identical. Because emissions of fluorides (as HF) triggered the significance threshold in Table 1.1, a BACT analysis was conducted for fluorides as HF (see Section 2.7 above). Based on evaluation of the feasibility of the available control techniques and the outcome of the BACT analysis for HF, the combination of a dry scrubber with a fabric filter baghouse was selected as the preferred control alternative for acid gases.

3.3 Summary of Control Alternatives Evaluation for Metals HAPs

3.3.1 Class 1 and 2 Metals HAPs

EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42") lists three classes of metals that are emitted from coal combustion (Refer to Section 1.2.3 for a description of each class). For Class 1 and 2 metals, the air emission control strategies are the same as those utilized for particulate matter. Thus, for a detailed evaluation of the control alternatives applicable to these classes of metals please refer to the evaluation for particulate control alternatives in Section 2.6 above. Based on evaluation of the feasibility of the available control techniques and the outcome of the BACT analysis for particulate, a fabric filter baghouse was selected as the preferred control alternative for Class 1 and Class 2 metals.

3.3.2 Class 3 Metals HAPs (Mercury)

A detailed evaluation of the control alternatives for Class 3 metals is included in the following text. While the evaluation below applies to both mercury and selenium, the discussion focuses specifically on mercury because mercury emissions are considered the primary pollutant of concern for the Class 3 metals group.

3.3.3 Control Alternatives Considered (Mercury)

Mercury is a naturally occurring element found in the earth’s crust. As a natural fuel extracted from the earth’s crust, coal contains trace levels of mercury. During the coal combustion process, mercury emissions may be generated in oxidized, elemental, or particulate form. A listing of potential control alternatives is provided in Table 17.

It should be noted that while some mercury may be captured collaterally with the controls designed for criteria pollutants, further emissions reductions can be achieved via the use of add-on controls.

TABLE 17
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Mercury emissions could be reduced by burning coals that contain less mercury content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Co-Benefit Control	The control alternatives WPEA has selected to control NO_x, SO_x and PM/ PM_{10} have been shown to reduce mercury emissions. This “native removal” of mercury by the control alternatives selected for criteria pollutants is known as “co-benefit” control.
Halogenated Activated Carbon Injection	Halogenated activated carbon sorbent is injected into the flue gas. The sorbent attracts and binds the mercury to its surface, and is then captured in a fabric filter baghouse.

3.3.4 Control Alternatives Eliminated (Mercury)

In this step, the potentially applicable control alternatives for the control of mercury emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 18 summarizes the technical feasibility evaluation for each control alternative listed in Table 17.

TABLE 18
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by mercury content.	No
Coal Cleaning/Coal Refining	The coal supply for the WPES has low characteristic mercury content and would not be expected to benefit significantly from coal cleaning. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Co-Benefit Control Alternatives	Co-benefit control alternatives have been proven to control boiler mercury emissions, and demonstrated in similar applications.	Yes
Halogenated Activated Carbon Injection (AVI)	There is extensive operating experience with activated carbon injection for waste incinerators. This technology is now commercially available for the power industry and is considered technically feasible.	Yes

3.3.5 Control Alternative Selected (Mercury)

Based on the analysis above, the combination of co-benefit control alternatives and halogenated activated carbon injection was determined to be the preferred control option for mercury and other Class 3 metals. The emissions limit for mercury was established as 0.00002 lb/Mwh on a rolling 12-month averaging period.

4.0 Greenhouse Gas Emissions

As stated in Section 1.4, greenhouse gases are components in the atmosphere that contribute to the greenhouse effect. CO_2 is considered the primary greenhouse gas of concern for fossil fuel combustion. Although CO_2 is not a regulated pollutant, it has recently been brought to the forefront in greenhouse gas discussions as a possible contributor to climate change.

Because add-on CO_2 removal technologies are not currently available (see Appendix E of this FEIS for additional information), the only means for minimizing CO_2 emissions are as follows:

- Select efficient generation technologies; and
- Increase electrical generation by emissions control systems that minimize parasitic load (electricity that is used within the power plant and not exported).

Because of advances in PC boiler technology, the WPEA facility will be 10 percent to 15 percent more efficient as compared to older PC power plants. The decreased fuel consumption associated with the WPEA facility's efficiencies results in decreased CO_2 emissions relative to the existing generation fleet. Additionally, CO_2 emissions are further minimized because of the lower parasitic load of the control alternatives (dry scrubber vs. wet scrubber) selected for the WPEA facility. The selection of dry scrubbing at the WPES results in CO_2 emissions 180,000 tons per year lower than a wet-scrubbed facility.

4.1 Future Planning

Future technological or regulatory developments may facilitate the feasibility of carbon capture systems. Retrofitting pollution control equipment at existing power facilities is difficult due the lack of spaces available between the boiler and stack. WPEA has set aside approximately 20 acres adjacent to the PC-fired boiler stacks where carbon capture equipment could be installed after this technology becomes technically feasible and commercially viable. For additional information on the capture-ready nature of the proposed Station, see Appendices E and F of this FEIS.

5.0 Works Cited

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