UTAH DIVISION OF AIR QUALITY
MODIFIED SOURCE PLAN REVIEW

George W. Cross,
President & Chief Operations Officer — Project fee code: N0327-010
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624-9522

RE:	PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station Millard County, Utah CDS-A, ATT, NSPS, HAPs, MACT, Title IV, Title V MAJOR
REVIEW ENGINEER:	Milka M. Radulovic
DATE:	March 22, 2004
NOTICE OF INTENT SUBMITTED:	December 16, 2002 & May 14, 2003
PLANT CONTACT:	George Cross
PHONE NUMBERS:	(435) 864-4414
FAX NUMBER:	(435) 864-6670
SOURCE LOCATION:	850 West Brush Wellman Road, Delta, Millard County, Utah
UTM COORDINATES:	4,374.4 km Northing, 364.2 km Easting, Zone 12 datum NAD27

Review:

Peer Engineer ____

John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A **30**-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact ____

(Signature & Date)

OPTIONAL: In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. THIS IS STRICTLY OPTIONAL! If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307-415-5a through 5e or R307-415-7a through 7i

"Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application)."

Responsible Official ____

(Signature & Date)

N:\mradulov\word\review\secretary\IPP-1.doc

TYPE OF IMPACT AREA

Attainment Area.. Yes

NSPS .... Yes

40 CFR Part 60, Subparts A, Da (Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After September 18, 1978), and Subpart Y (Coal Preparation Plants) at this time. However there is proposed new NSPS for this source category

NESHAP.................... No (At this time. However there is proposed new NESHAP for this source category)
MACT ....Yes (case-by-case MACT)
Hazardous Air Pollutants (HAPs) .... Yes (from combustion)
Hazardous Air Pollutants Major Source.. Yes
New Major Source...No
Major Modification.. Yes
PSD Permit... Yes
PSD Increment (modeling) .... Yes

Operating Permit Program

Area Source..No
Major .... Yes

Send to EPA... Yes
Comment period..30-day

FOR MODIFIED SOURCES

The Notice of Intent is for a modification to an existing source. The following standards are applicable to this review:

NSPS applies to modification?.. Yes
PSD review of entire source required? .... Yes
NESHAPS applies to modification? ....No (At this time. However there is proposed new NESHAP for this source category)
HAPs involved in modification? .... Yes
TITLE V required for entire source?.. Yes
HAPs MAJOR for modification?... Yes
NONATT MAJOR for entire source?..No

Abstract

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Plant (IPP) site located near the town of Delta in Millard County, Utah. The existing plant has two drum-type, pulverized coal (PC)-fired boilers that provide steam to two power-generating units, designated as Unit 1 and Unit 2, each with nominal gross capacity of 950 MW. The Intermountain Power Service Corporation (IPSC) submitted Notice of Intent to expand the IPP facility by adding one additional base load pulverized coal fired electricity generating Unit 3, designed at nominal 950-gross MW (nominal 900-net MW) with dry bottom, tangentially fired or wall-fired boiler and associated equipment. Unit 3 will be equipped with wet flue gas desulphurization (WFGD), selective catalytic reduction (SCR), and baghouses for control of the various emissions.

This project is a major modification for the Prevention of Significant Deterioration (PSD) regulations. On site meteorological monitoring, air dispersion modeling, air quality impacts analysis (including HAPs emissions) including visibility and PSD class I and II impacts analysis, non-attainment boundary impact analysis, and a complete top-down Best Available Control Technology (BACT) review were completed and submitted by the IPSC as a part of their Notice of Intent (NOI). Also, an application for case-by-case maximum achievable control technology (MACT) determinations for hazardous air pollutants (HAPs) was provided as a part of the NOI. Unit 3 is also subject to New Source Performance Standards under 40 Code of Federal Regulations (CFR) 60, Subparts A, Da and Y. Title IV and Title V of the 1990 Clean Air Act apply to this modification and the Title V permit shall be amended prior to the operation of the Unit 3. Unit 3 boiler will be classified Group1, Phase II under the Acid Rain Program. As a result of the performed air quality impacts analysis two auxiliary boiler stack heights will be raised to be no less than 72 feet, as measured from ground level at the base of the stack. The increment analysis indicated that the amount of PM_{10} 24-hour increment consumed by the proposed project would be greater than 50% of the standard; therefore, approval under Utah Administrative Code R307-401-6 (3) from the Utah Air Quality Board would be required. The IPP will meet all primary and secondary National Ambient Air Quality Standards (NAAQS). The IPP will also meet Class I increments in the National Parks in southern Utah and Class II PSD increments in the vicinity of the plant.

The IPP is located in Millard County, an attainment area for all criteria pollutants.
Estimated potential to emit totals from Unit 3, in tons per year, are as follows: PM_{10} 617.15, NO_x 2775, SO_2 3,963.9, CO 5946, VOC 107, HAPs 199.

Newspaper Notice

The Intermountain Power Service Corporation (IPSC) submitted Notice of Intent to expand the IPP facility by adding one additional base load pulverized coal fired electricity generating Unit 3, designed at nominal 950-gross MW (nominal 900-net MW) with dry bottom, tangentially fired or wall-fired boiler and associated equipment. Unit 3 will be equipped with wet flue gas desulphurization (WFGD), selective catalytic reduction (SCR), and baghouses for control of the various emissions.

It has been determined that the conditions of the Utah Administrative Code R307-401-6 and the Federal rules have been met. The Executive Secretary intends to issue an Approval Order after a 30-day public comment period is held. This comment period is being held to receive and evaluate public input on the project proposed by Intermountain Power Service Corporation.

I. <u>DESCRIPTION OF PROPOSAL</u>

This review contains concise information of the proposed project and includes a description only of those systems, which contain or affect this facility's air emissions. Systems that do not contain or impact air emissions are not included in the review.

Following listed information can be found in the May 14, 2003 IPSC NOI, Appendix I:

1.Coal Supply
Intermountain Power Project (IPP) Unit 3 Coal Supply, May 13, 2003
2.Modeling
Replacement Graphics for IPP NOI May 14, 2003 Addendum, May 27, 2003
Replacement Sections and Files for the IPP NOI May 14, 2003 Addendum, June 18, 2003
IPP Unit 3 Start-Up & Shut-Down Modeling, July 28, 2003
White Paper: PM10 Impacts in Utah County, October 16, 2003
Replacement Sections and Files for the IPP NOI May 14, 2003 Addendum, October 31, 2003
IPP3 Project CALPUFF: Observed Weather Conditions for Days with Natural Obscuration, November 6, 2003
IPP3: Revised Cumulative Class I Increment Modeling, December 16, 2003
3. PM_{10} BACT
PM_{10} Emissions and Fabric Filter Control Efficiency, May 13, 2003
IPP Unit 3—PM_{10} BACT Cost Estimate, November 7, 2003
IPP Unit 3—PM_{10} BACT Questions, November 7, 2003
IPP Unit 3—PM_{10} BACT Questions, December 18, 2003
PM_{10} BACT Cost Analysis, January 12, 2004
4. NO_X BACT
Nitrogen Oxide Emissions and Control, May 13, 2003
5. SO_2 BACT
Flue Gas Desulfurization – Control Efficiency, May 13, 2003
SO_2 Control - Effect of Averaging Time on Wet FGD System Performance and Design, May 13, 2003
Wet Flue Gas Desulfurization Control Efficiency, submitted November 18, 2003
5. Sulfuric Acid Mist
Evaluation of Wet Electrostatic Precipitation to control Sulfuric Acid Mist Emissions, May 13, 2003
6. CO/VOC BACT
IPP Unit 3 Air Permit Application: Review of CO and VOC Permit Limits (revised), September 8, 2003
7. Response to UDAQ BACT Questions
Generating Technology BACT Evaluation
Intermountain Power Project Unit 3 Permit Application: Response to UDAQ Questions, July 28, 2003
8. Mercury MACT
IPP Unit 3 Air Permit Application: Review of Mercury Permit Conditions (revised), September 8, 2003
9. Evaluation of Integrated Gasification Combined Cycle and Circulating Fluidized Bed Paper, November 26, 2003

1. Project Description

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Plant (IPP) site located near the town of Delta in Millard County, Utah. The existing plant has two drum-type, pulverized coal (PC)-fired boilers that provide steam to two power-generating units, designated as Unit 1 and Unit 2, each with nominal gross capacity of 950 MW. IPSC submitted Notice of Intent to expand the IPP facility by adding one additional nominal 950-gross MW (nominal 900-net MW) unit designated as Unit 3 with associated equipment.

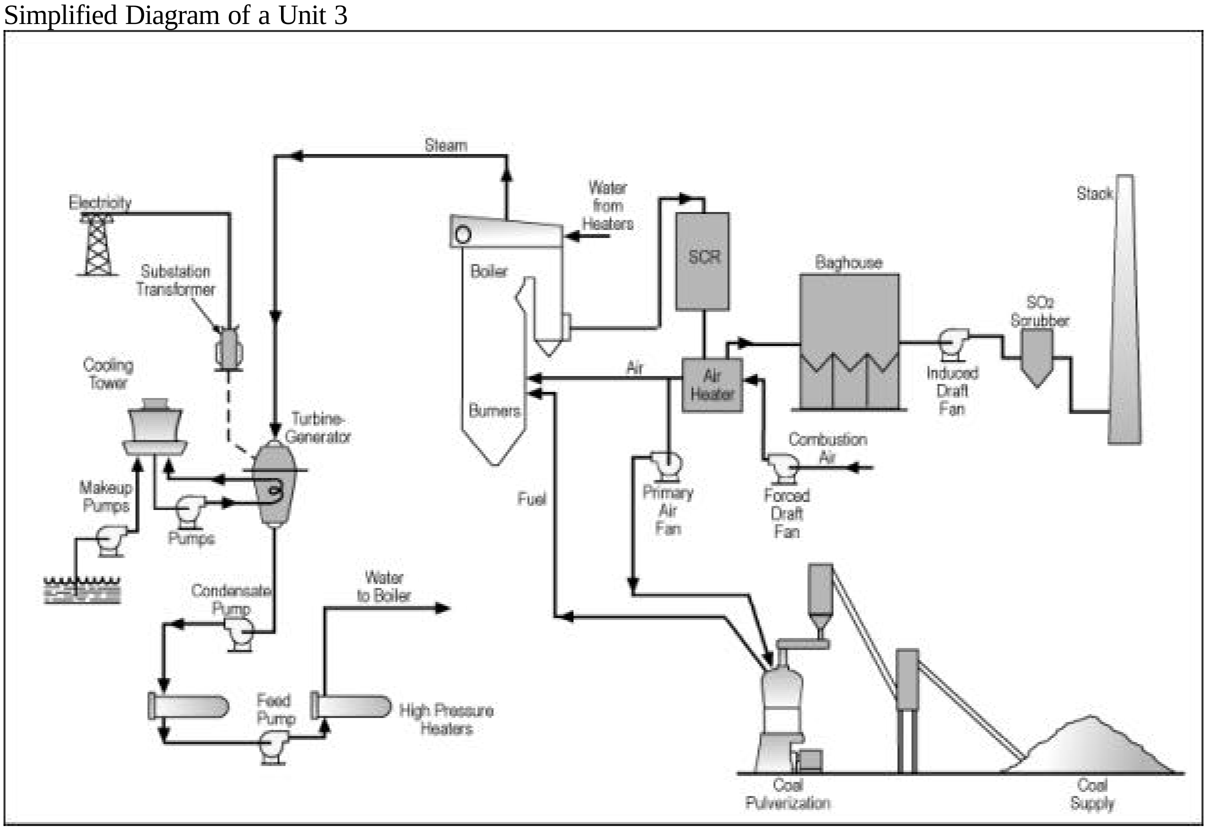
Unit 1 and 2 are permitted under AO DAQE-AN0327009-04.

The IPP facility is located in Millard County, near the town of Delta, in the Sevier Desert of west central Utah. The IPP facility is situated in a broad valley, an area of relatively low population density, and that is favorable to plume dispersion. The nearest Class I area is located approximately 149 kilometers (km) southeast [Capitol Reef National Park (NP)].

A. Proposed Unit 3 Description

The new Unit 3 will consist of the same sub-systems as Units 1 and 2. In addition, Unit 3 will have a selective catalytic reduction (SCR) control system as part of the emissions control equipment.

Simplified Diagram of a Unit 3



The Unit 3 boiler flue gases will utilize the following emissions controls:

- Wet limestone flue gas desulfurization system (WFGD),

- Ultra or equivalent Low NO_x Burners (LNBs), overfire air (OFA), and Selective Catalytic Reduction (SCR), and
- Reverse air baghouse;

The clean flue gases will be exhausted a through a single 712-foot stack to the atmosphere.

A.1. Proposed Unit 3 Process Description

The proposed Unit 3 boiler will be an indoor-type, sub critical, PC-fired boiler designed for base load operation. The unit will have a maximum gross heat input (at 105% boiler design capacity) of approximately 9,050 MMBtu/hr and a plant electrical output of approximately 950-gross MW. The proposed primary fuel for Unit 3 will be western bituminous coal. However, the unit will be designed to burn blends of western bituminous and sub-bituminous coal. No. 2 fuel oil will be used for light off, startup, and flame stabilization. No. 2 fuel oil is stored in the existing aboveground tanks, which are located on the plant site and currently serve Units 1 and 2. No additional oil storage is planned for Unit 3. The total amount of oil burned per year will be approximately 50,000 barrels per year in the existing auxiliary boiler for all three units. No increase in the existing auxiliary boilers fuel oil consumption is requested for the addition of the Unit #3.

The design fuel characteristics for the proposed coal are shown in the table below.

Worst-Case Design Coal Characteristics

Parameter	Units	Worst-Case Design Coal[a]
*Gross (Higher) Heating Value	Btu/lb	11,193
*Gross Heating Value (Dulong)	Btu/lb	11,612
*, **Moisture	wt percent	8.26
*Volatile Matter	wt percent	37.0
*Fixed Carbon	wt percent	43.0
**Average Maximum[b] Sulfur Content	wt percent	0.75
*, **Average Maximum[b] Ash Content	wt percent	12.0
Average Maximum[b] Uncontrolled SO_2 Emission Rate	lb/MMBtu	1.34
**Carbon	percent	64.5
**Oxygen	percent	8.9
**Hydrogen	percent	4.66
**Nitrogen	percent	1.26
**Chlorine	percent	0.03

[a] The term "worst-case design coal" is used to describe a coal that exhibits characteristics (i.e., heating value, sulfur content, ash content, moisture, etc.) that envelop the characteristics described above. Worst-case design coal will generate the highest pollutant emission rates, and is used, therefore, to ensure that emission control systems are designed to ensure compliance with permitted emission limits recognizing the potential variability in the fuel.

[b]*Average maximum* is defined as the maximum coal characteristic value based on an average of sample results collected over a calendar year.

[c]-Based on EPA's Emission Factors Compilation AP-42, Table 1.1.3 (9/98)

*Coal Proximate Analysis

**Coal Ultimate Analysis

Coal Ash Analysis

Silica	63.2 %
Ferric Oxide	3.3 %
Alumina	15.5 %
Titanic Oxides	0.8 %
Calcium Oxide	7.1 %
Magnesia	2.9 %
Sulfur Trioxide	4.2 %
Potassium Oxide	1.0 %
Sodium Oxide	2.4 %
Phosphorous Pentoxide	0.2 %

It is anticipated that the Unit 3 boiler will be a dry-bottom, tangentially fired or wall-fired (front and rear) boiler with LNBs and OFA-ports. Specifications for the proposed boiler are included in the table below

Boiler Design Parameters

Plant Parameter[a]	Units	Design Parameters
Nominal Gross Plant Output	Gross-kilowatt (kW)	950,000
Steam Temperature	^{o}F	1,050
Main Steam Pressure	psig	2,520
Gross Plant Heat Rate - HHV	Btu/gross-kilowatt hour (kWh)	9,072
Net Plant Heat Rate -HHV	Btu/net-kWh	9,790
105% Design Load Heat Input to Boiler – HHV	MMBtu/hr	9,050
Coal Feed Rate	tph	404
Maximum Fuel Oil Feed Rate[b]	gph	10,000

[a] The numbers in this table are preliminary design estimates.
[b] 15 percent of full load heat input

A.2 Unit 3 Boiler Proposed Pollution Control Equipment

This section describes the air pollution control equipment that is proposed IPP Unit 3 boiler for applicable pollutants.

Flue gas from Unit 3 will pass through a series of post-combustion emissions control devices, proposed under the BACT part of this review.

A.2.1. Wet Flue Gas Desulfurization (WFGD) System

All Unit 3 boiler exhaust gases will pass through the limestone WFGD system.

The Unit 3 FGD system is being designed with two absorber modules (rather than one). Each absorber vessel is being designed to treat a nominal 67% gas flow under normal operating conditions. In addition, the vessels are being designed to be capable of treating 100% of the flue gas flow under extraordinary conditions. Under normal operating conditions, each vessel will treat 50% of the flue gas. Gas flow velocity through the vessels under normal operating conditions will be approximately 8 – 9 fps. In the event that one of the reaction vessels is taken out of service, the other vessel will be capable of receiving 100% of the flue gas flow. Under these conditions, gas flow velocity through the vessel will increase to approximately 15 fps. The scrubbers will be designed to control SO_2 emissions from the worst-case coal parameters presented in this review.

The WFGD system will be designed to consistently achieve a controlled SO_2 emission rate of 0.10 lb/MMBtu. Based upon the coal characteristics, the WFGD system will be designed to reduce SO_2 emissions by about 92.5 percent.

Proposed FGD Operating Parameters

Parameter	Units	Estimated Design Value	Notes
General Description		Wet Limestone FGD	
Number of Scrubber Modules		Two ~67 percent Modules	
Flue Gas Flow Rate	acfm	3,617,117	At 105-percent design load
Flue Gas Temperature (inlet)	^oF	275 – 300	
Pressure Drop Through Scrubber	inH_2O	8 (typical)	
Inlet SO_2 Concentration	lb/MMBtu	1.34	Worst Design coal
Outlet SO_2 Concentration	lb/MMBtu	0.10	Maximum SO_2 emission rate
SO_2 Removal Efficiency	percent	~92	Based on worst-case design
HCl Removal Efficiency	percent	90	
Fluorides/HF Removal Efficiency	percent	90	
Calcium to Sulfur Molar Ratio		1.03	
Limestone Feed Rate	lb/hr	20,072	At 105-percent design load
Sorbent Analysis		$CaCO_3$ 90 percent $MgCO_3$ 3 percent CaO 0 percent Ash 6.5 percent Moisture 0.5 percent	Typical limestone sorbent analysis
Scrubber Sludge Generation Rate	lb/hr	32,429	At 105-percent design load

The wet limestone FGD system will also be used to control emissions of sulfuric acid and acid gases, other sulfur compounds, soluble Hg, from IPP Unit 3. Based on source test information obtained from IPP Unit 1, it is anticipated that the overall H_2SO_4 removal efficiency across the baghouse and the wet limestone FGD system will be approximately 90 percent.

A.2.2. Unit 3 Boiler NO_x Control Technologies

IPP Unit 3 boiler will be equipped with Ultra or equivalent LNBs and OFA system as combustion control for NO_x and with a SCR unit for post combustion control of NO_x emissions.

Ultra or equivalent Low NO_x burners limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope.

In the OFA process, the injection of air into the firing chamber is staged into zones. The staging of the combustion air reduces NO_x formation by two mechanisms. The staged combustion results in a cooler flame, and the staged combustion results in less oxygen reacting with fuel molecules. However, the degree of staging is limited by operational problems. Excessive staging can result in incomplete combustion conditions and increased CO and VOC emissions.

The combination of these two combustion control techniques produces lower NO_x emissions during the combustion process.

The proposed SCR is designed for high dust loading applications, and will be located externally from the boiler. The SCR system uses a catalyst and a reactant [ammonia gas (NH_3)] to dissociate NO_x into nitrogen gas and water vapor. The system will be designed to use anhydrous ammonia as the reducing agent.

The anticipated SCR operating parameters are summarized in the table below.

<u>SCR Operating Parameters</u>

Parameter	Unit	Estimated Design Value
Catalytic Reaction Temperature	^oF	675 - 725
Inlet Gas Temperature	^oF	700 - 715
Design Inlet Gas Flow Rate	acfm	3,800,000
Reducing Agent		Anhydrous Ammonia
Maximum Ammonia Feed Rate	lb/hr	993
NO_x Inlet Concentration	ppmvd @ 3 percent O_2	250 (0.35 lb/MMBtu)
NO_x Outlet Concentration	ppmvd @ 3 percent O_2	50 (0.07 lb/MMBtu)
NO_x Control Efficiency	percent	80
Ammonia Slip	ppmvd @ 3 percent O_2	5
Catalyst Life	years	2 - 3

A.2.3. Baghouse

A negative pressure fabric filter dust collector system (or "baghouse") will be provided for Unit 3 boiler to remove PM and PM_{10} from the flue gas stream. The fabric filter system will consist of a number of parallel banks of individual filter compartments located downstream of the air preheaters and upstream of the FGD system

PM captured on the filter bags will form a filter cake. The filter cake increases both the filtration efficiency of the cloth and its resistance (pressure drop) to gas flow.

It is anticipated that the Unit 3 fabric filter system will be designed as a reverse-air system.

Fabric filter system design involves inlet loading rates, fly ash characteristics, the selection of the cleaning mechanism, and selection of a suitable bag fabric and finish. Specific design parameters were not established since the actual fabric filter manufacturer has not been determined; however, the fabric filter system will be designed to achieve a maximum filterable PM_{10} emission rate of 0.015 lb/MMBtu. Controlling filterable PM_{10} emissions to a rate of 0.015 lb/MMBtu represents a control efficiency of 99.825 percent (based on the estimated inlet particulate loading, 8.58 lb/MMBtu).

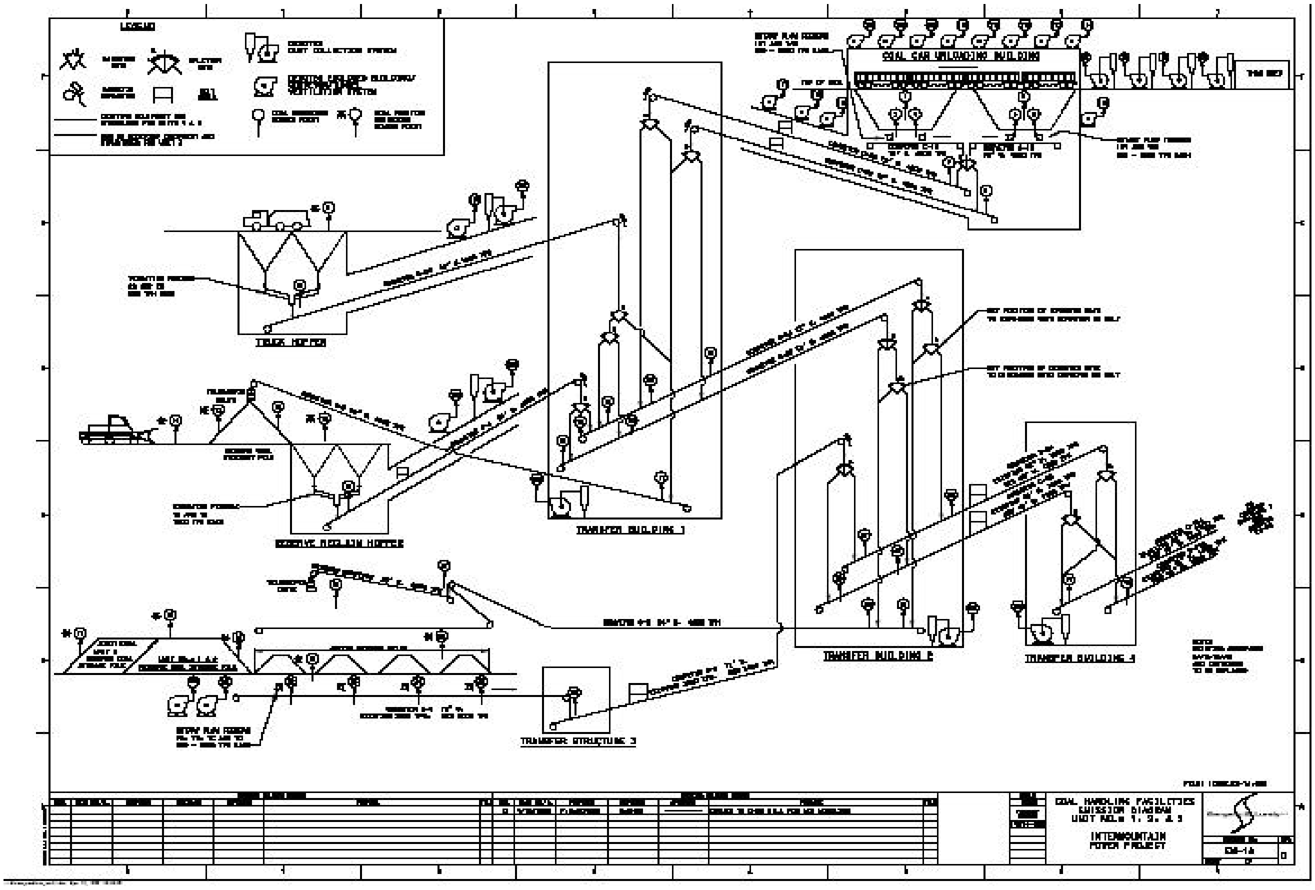
Anticipated fabric filter system parameters are summarized in the table below.

Anticipated Fabric Filter Design Parameters

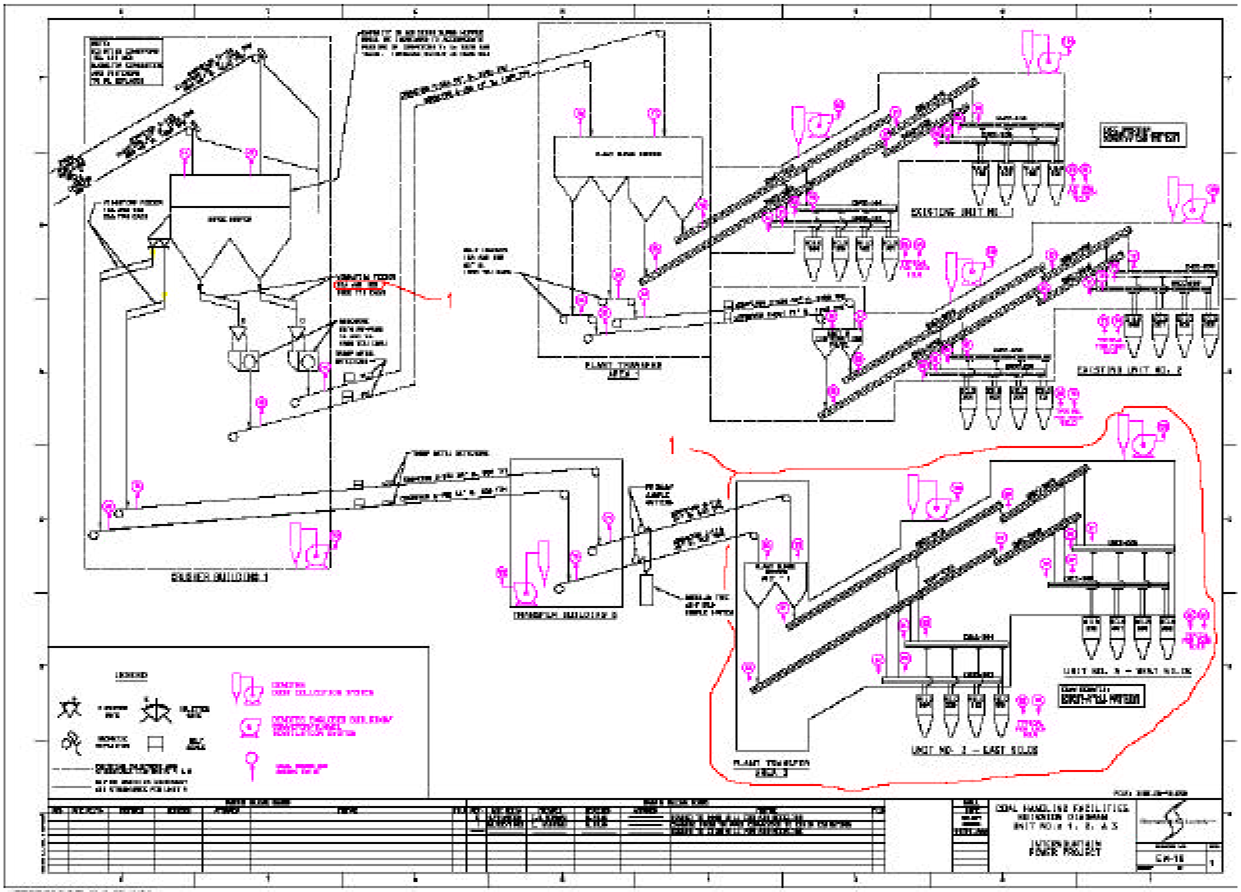
Parameter	Units	Estimated Design Value
Flue Gas Flow Rate to Fabric Filter	acfm	3,617,117
Inlet Gas Temperature	^{o}F	275 - 300
Inlet Particulate Loading	lb/hr	77,616 (8.58 lb/MMBtu)
Outlet Filterable PM_{10} Loading	lb/MMBtu	0.015
Outlet Filterable PM_{10} Loading	lb/hr	136
Collection Efficiency	%	99.825
Bag Material		Ryton or equivalent
Bag Diameter, Length, Number of Bags		Undetermined
Number of Modules and Compartments per		Undetermined
Air to Cloth Ratio	$acfm/ft^2$	2:1
Pressure Drop Across Bags	inH_2O	5 - 6 (typical)
Cleaning Mechanism and cycle		Reverse Air

A.3. Unit 3 Fuel Handling

Coal will be primarily delivered to the plant by rail and alternately in trucks. The coal will be delivered to the coal shed and transferred to the plant by means of covered conveyors. Because of the addition of Unit 3, some changes will be made to the existing coal handling system and these changes are shown below in the following drawings:



LEGEND
COAL CAR UNLOADING BUILDING
TRUCK HOPPER
RESERVE RECLAIM HOPPER
TRANSFER BUILDING 1
TRANSFER BUILDING 2
TRANSFER BUILDING 4
TRANSFER STRUCTURE 3
COAL HANDLING FACILITIES
EMISSION DIAGRAM
UNIT NO.s 1, 2, & 3
INTERMOUNTAIN
POWER PROJECT



The above shown diagram is schematic flow diagram of the existing and modified coal handling system for Units 1, 2, and 3, and the emission points associated with the coal handling system.

In order to accommodate the increased burn rate due to the new Unit 3 boiler, the existing coal reclaiming and silo fill systems will require modification.

A.3.1 Existing Coal Handling System

A summary of the existing coal handling conveyor system is provided in the table below.

Existing Coal Handling Conveyor System

Conveyor Designation	Belt Width	Capacity tons per hour (tph)
Conveyors 1A/1B	72"	4,000
Conveyors 2A/2B	72"	4,000
Conveyor 3	72"	4,000
Conveyor 4	54"	2,000
Conveyors 5A/5B	72"	4,000
Conveyor 6 with traveling stacker	96"	6,000

Conveyor 7	72"	2,000
Conveyor 8	72"	2,000
Conveyors 9A/9B	42"	1,000
Conveyors 15A/15B	42"	1,000
Conveyors 18A/18B	42"	1,000
Conveyor 30	42"	1,000
Conveyors 201/202	42"	1,000
En Masse Chain Conveyors	630mm	600

Coal is received from unit trains with bottom dump cars at the coal car unloading building and from rear or bottom dump trucks at the coal truck unloading hopper onto Conveyors 1A and 1B and Conveyor 30, respectively. The coal is transferred onto Conveyor(s) 2A and/or 2B by means of a splitter gate.

The coal truck unloading system is designed with two hopper sections. The hoppers receive the coal from bottom dump and rear dump trucks. Each hopper is equipped with a 500 tph variable rate-vibrating feeder. Coal from the coal truck unloading hopper is conveyed to Transfer Building 1 via Conveyor 30. By means of diverter gates, coal is discharged onto Conveyor 3, 5A, or 5B.
Coal from the coal car unloading building is transferred to Conveyors 2A and 2B which convey the coal to Transfer Building 1. Conveyor 2A diverts coal to either Conveyor 3 or Conveyor 5A by means of a diverter gate. Similarly, Conveyor 2B diverts coal to either Conveyor 3 or Conveyor 5B. Conveyors 5A and 5B convey the coal to Transfer Building 2.

Conveyor 3 conveys coal to the coal reserve stock out pile. Coal in the reserve stock out pile is transferred by mobile equipment to either the reserve coal storage pile or reclaim hopper when needed. The reclaim hopper is designed with two hopper sections. Each section is equipped with a 1,000 tph variable rate-vibrating feeder. The coal from the hopper is discharged onto Conveyor 4 via feeders and is transported to Transfer Building 1 where it is transferred to either Conveyor 5A or 5B by means of a diverter gate.

In normal operation, due to an uneven split (2,000 and 1,000 tph) from Conveyor 5A to Conveyors 6 and 9A, and from Conveyor 5B to Conveyors 6 and 9B in Transfer Building 2, some of the coal unloaded at the coal car unloading building is diverted to an active storage pile via Conveyor 6. The rotary plow feeder(s) located under an active storage pile reclaims the coal from the storage pile and discharges it onto Conveyor 7. Coal is transferred from Conveyor 7 to Conveyor 8 in Transfer Structure 3 and conveyed to Transfer Building 2. Conveyors 9A and/or 9B receive coal from Conveyor 8 by means of a splitter gate and deposit into the surge hopper in Crusher Building 1 via Conveyors 15A and/or 15B. Alternately, all of the coal unloaded at the car unloading building can be conveyed at a reduced rate (1,000 or 2,000 tph) to Units 1 and 2 silos directly.

Coal is removed at a controlled rate from the crusher surge hopper and discharged onto Conveyors 18A and/or 18B via crusher bypass chutes. The station currently receives sized coal so the crushers are being bypassed. Conveyors 18A and 18B convey coal to the plant surge hopper located in Plant Transfer Area 1. From the surge hopper, coal is transferred to the Unit 1 and 2 in-plant silos via conveyor systems.

There is some redundancy in the conveyor system. A dual conveyor system is provided from the coal car unloading building to the Unit 1 and 2 in-plant silos. Also a reserve stock out/reclaim system is provided in case an active storage/reclaim system is out of service. Capacity of the single conveyors of the dual reclaim/silo fill conveyor system is adequate to supply coal to Units 1 and 2.

A.3.2. Proposed Modifications and Additions to Existing Active Reclaim and Silo Fill Systems

These modifications and additions to existing active reclaim and silo fill systems are necessary to accommodate the addition of proposed Unit 3 and the table below lists the proposed modifications to the belt conveyor system.

Modification to the Existing Coal Handling Conveyor System

Conveyor Designation	Belt Width		Capacity TPH		Remarks
	Exist	New	Exist	New	
Conveyor 7	72"	----	2,000	3,000	New drive components
Conveyor 8	72"	----	2,000	3,000	New drive components
Conveyors 9A/9B	42"	48"	1,000	1,500	New belting, idlers, pulleys, drive components, chute work, scrapers, and belt scales Existing bents, trusses, and conveyor support stringers
Conveyors 15A/15B	42"	48"	1,000	1,500	New belting, idlers, pulleys, drive components, chute work, scrapers, and magnetic separators Existing bents, trusses, and conveyor support stringers

In the table below are listed proposed new coal handling conveyors for the addition of Unit 3.

Proposed New Coal Handling Conveyors

Conveyor Designation	Belt Width	Capacity TPH	Belt (chain) Speed FPM	Remarks
Conveyors 16A/16B	36"	600	450	
Conveyors 17A/17B	36"	600	450	
En Mass Chain Conveyors 301A/B, 302 A/B, 303, 304, 305, and 306	24"	600	(135)	Totally enclosed conveyors

The capacity of the existing coal train unloading and stock out system is adequate to supply coal to Units 1, 2, and 3.

In normal operation, coal is delivered directly to the units from coal unloading. Some may be diverted to the coal pile: all if the unit silos are full. In worst case operation, due to an uneven split, the coal received at the coal car unloading building will be transferred to an active storage pile via Conveyors 1A/B, 2A/B, 5A/B, and 6. Capacity of the existing reserve coal storage pile will be increased by approximately 624,000 tons to support Unit 3. This is based on a 65-day coal supply to operate Unit 3 at a burn rate of 400 tph.

Alternately, when an active reclaim system is out of service and coal is being unloaded at the coal car unloading building, coal flow from Conveyor 5A will be split in half by means of a splitter gate located in the discharge chute. Conveyor 9A will receive a maximum of 1,500 tph and will supply coal to the Units 1, 2, and 3 in-plant silos. The balance of the coal from Conveyor 5A will be discharged onto Conveyor 6. Similarly, coal flow from Conveyor 5B can be split.
The capacity of existing Conveyors 7, 8, 9A/B, and 15A/B will be increased to support Unit 3. See Table 7 for the modification of existing Conveyors 7, 8, 9A/B, and 15A/B.

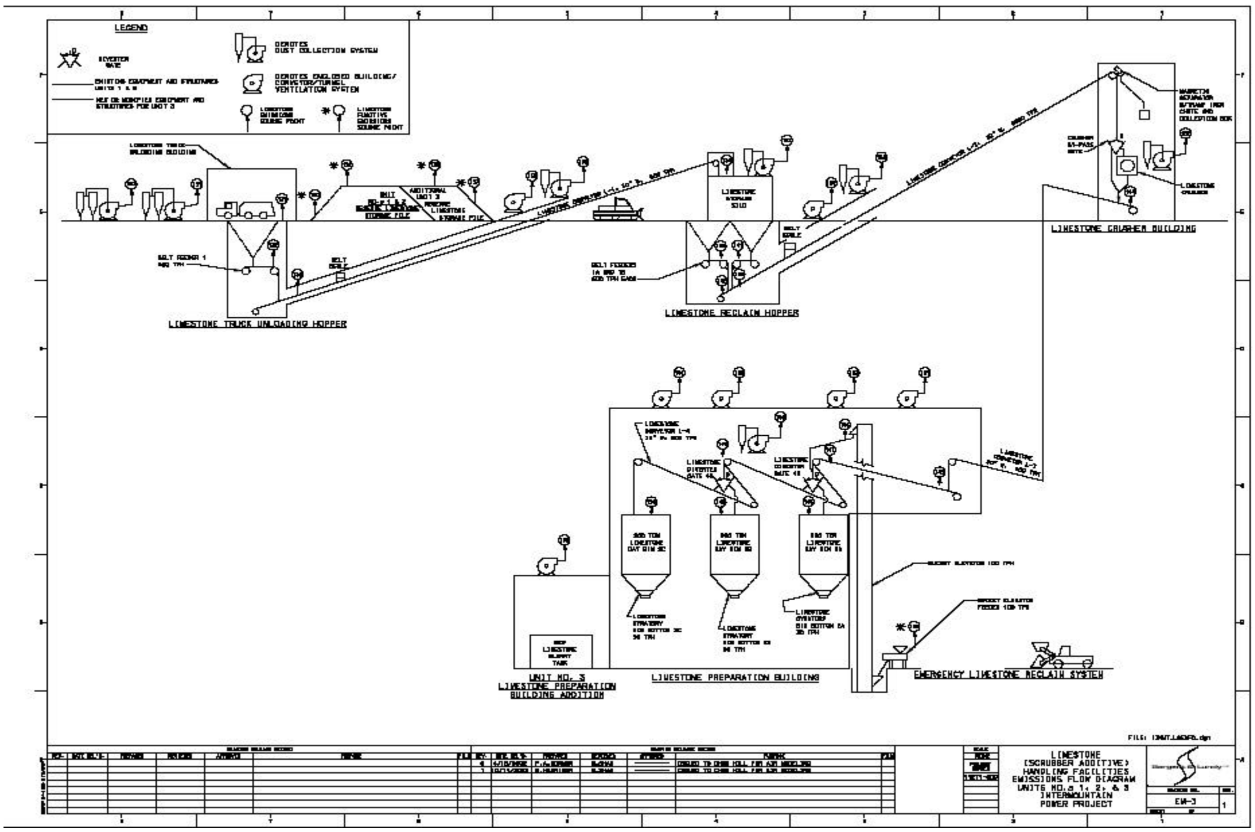
During reclaiming operation, the rotary plow feeder(s) will reclaim the coal from the active storage pile at a controlled rate, maximum 3,000 tph, and discharge onto Conveyor 7. Conveyor 8 will receive coal from Conveyor 7 and transfer to either Conveyor(s) 9A, 9B, or both via a splitter gate in Transfer Building 2. Conveyors 15A and 15B will receive coal from either Conveyor 9A or 9B via a diverter gate in Transfer Building 4 and deposit it into the surge hopper located in Crusher Building 1.

Modifications will be made to the surge hopper in Crusher Building 1 to increase the storage capacity and to provide two additional outlets for the installation of two new vibrating feeders that will feed coal to new Conveyors 16A and 16B. Conveyors 16A and 16B will discharge coal onto new Conveyors 17A and 17B respectively in Transfer Building 5 and transport to Plant Transfer Area 3. A new as-fired coal sampling system will be provided at Transfer Building 5.
At Plant Transfer Area 3, Conveyors 17A and 17B will discharge coal into the Plant Surge Hopper. Coal will then be transferred from the plant surge hopper to two 600-tph en masse chain conveyors (EMCCs) -301A and 302A. The silo fill system will consist of two EMCCs-301B and 302B across the back of the unit, two EMCCs-303 and 304 serving east silos and two EMCCS-305 and 306 serving west silos. Silo filling can be accomplished by several methods. The first method is to fill each silo, one at a time, by directing the flow of coal using the chain conveyor discharge gates. A high-level probe will determine when the silo is filled. Coal will then be directed to the next silo or any silo that needs to be filled by opening the discharge gate. This process will continue until all silos are filled. The second method of silo filling is to leave all the chain conveyor discharge gates feeding the silo row open. Coal will then fill the first silo in the row and then flow to the next silo in the row until they are completely filled. The third method would be a combination of the two preceding methods.

Refer to the above for the new conveyor's belt size and capacity. No modifications will be required for the existing silo fill system for Units 1 and 2. Redundancy in the system is supplied via a dual conveyor system from the existing crusher in Building 1 to Unit 3 plant silos. A single conveyor system will be used to supply coal to Unit 3 boiler.

The coal storage and handling system will have particulate controls to reduce fugitive dust emissions. Water sprays will be directed to coal unloaded at the coal car unloading building, for transfer out to storage. The inactive coal storage pile will be controlled by the application of a chemical binder. Enclosures with fabric filters will be used for the transfer points, silos, and crusher houses on the coal handling system.

A4 Limestone Handling



The above shown diagram is schematic flow diagram of the existing and modified limestone handling system for Units 1, 2, and 3, and the emission points associated with the limestone handling system.

The capacity of existing limestone truck unloading and reclaiming system is adequate to supply limestone to Units 1, 2, and 3. Capacity of the existing 40,000 square feet (ft^2) limestone reserve storage pile will be increased by approximately 8,000 ft^2 to support Unit 3.

The total limestone usage for all three units will be approximately 200,000 tpy dependent on the specific coal and plant capacity factor. The maximum annual limestone usage for Unit 3 is approximately 88,000 tons. At maximum load (105% of the design load), the Unit 3 WFGD system will require 20,072 pounds of limestone per hour.

The table below shows the modifications and additions required to the existing limestone day bin fill and preparation systems as a result of the Unit 3 addition.

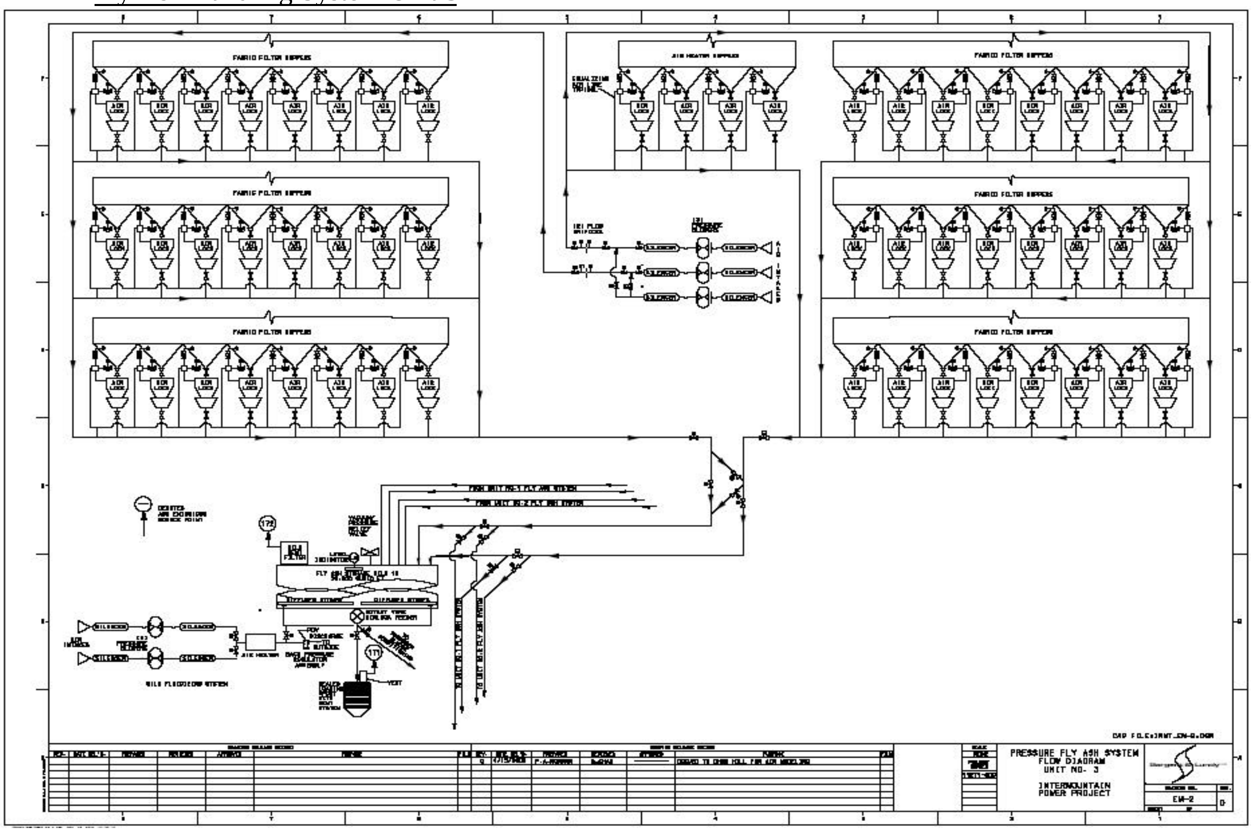
Limestone Handling Modifications and Additions

Limestone Consumption	20,072 lbs/hr (10 tph)

Limestone Preparation System	New limestone slurry tank and associated pumps, valves, piping, and controls Add new structure to the existing building to enclose the new slurry tank and pumps

A.5 Ash and Combustion By-Product Collection, Transport, and Disposal

Fly Ash Handling System Unit 3



The above shown is schematic flow diagram of the fly ash handling system for Unit 3, and the emission points associated with the fly ash handling system.

The pneumatic pressure type fly ash handling system for Unit 3 will convey the fly ash collected in the fabric filter and air heater hoppers to new Fly Ash Storage Silo 1C or existing Storage Silos 1A or 1B.

The fly ash handling system serving the fabric filter and air heater hoppers will be divided into two equally sized and independently operated pressure subsystems with a combined conveying capacity of 150 tph (75 tph per subsystem). One subsystem will serve three rows of fabric filter hoppers with eight outlets per row. The second subsystem will serve the other three rows of fabric filter hoppers with eight outlets per row and one row of air heater hoppers with four outlets. Cross-ties at the fabric filter will be provided in the transport piping so that all fly ash hoppers can be emptied using one of the subsystems. In addition, the transport piping at the silos will be cross-tied with the fly ash systems from Units 1 and 2 to permit fly ash from any unit to be conveyed to any silo.

The fly ash handling system will consist of air lock type pressure feeders, ash transport piping, branch isolation valves, crossover valves, mechanical blowers for conveying air, mechanical blowers for fluidizing air, fly ash storage silo with vent filter, and truck/rail car dry ash loading spout with vent filter.

The net storage capacity of the ash silo will be 50,000 cubic feet (ft^3). This will provide approximately 36 hours of storage for the fly ash. The silo vent filter will be equipped with a bag type vent filter system and designed to remove fly ash carryover from the air stream exiting the fly ash silo. The minimum design efficiency of the vent filter will be 99.9 percent. The vent filter will be sized to accommodate the airflow resulting from the simultaneous discharge of four 70 tph conveying systems into the silo.

The fly ash storage silo will be equipped with a complete fluidizing air system including the porous fluidizing media, mechanical blowers, electric air heaters, and inlet filter silencers.
Fly ash destined for sale to outside markets will be loaded into totally enclosed trucks or railcars by a dry unloading system, which features a sealed loading spout with a vent system equipped with bag filters. Fly ash destined for disposal will be mixed with scrubber waste in a scrubber sludge/fly ash mixer as it is unloaded from the silo and conveyed via belt conveyors to the disposal area. This will minimize dusting during unloading.

The fly ash system will be provided with an automatic control system to empty the fabric filter and air heater hoppers and transport the ash to a fly ash silo(s). The control system will provide an automatic sequential operation of the branch isolation valves with provisions to bypass any one hopper or group of hoppers.

Upon actuation of the system controls, each active pressure feeder located under the fabric filter and air heater hoppers will be vented to the associated fly ash hopper and the upper feed gate will be opened. Fly ash will flow into the pressure feeder assisted by the fluidizing air. After a predetermined time, the upper feed gate will be closed and the feeder pressurized slightly above the conveying header air pressure. The lower feed gate will then open allowing the fly ash to discharge into the conveying air stream. When the feeder is empty, the bottom gate will close and the cycle will be repeated until the hopper is empty. The fly ash will be conveyed through the transport pipe to a storage silo.

The fly ash storage and handling system will have particulate controls to reduce fugitive dust emissions. Enclosures with fabric filters will be used for the fly ash transfer points and storage silos.

A.6. Bottom Ash Handling System Unit 3

The bottom ash handling system for Unit 3 will include removal and disposal of bottom ash to the existing ash disposal ponds. Bottom ash is generated from the following:

- Bottom ash from the steam generator
- Boiler hopper ash

- Pulverizer rejects

The system will be similar to the existing bottom ash system for Units 1 and 2. Water supply and transport components will be sized to have 25 percent more capacity than the existing system. The new ash water tank for Unit 3 will have a capacity of 250,000 gallons and will be cross-tied to Units 1 and 2.

The 6-day bottom ash storage area is essentially a concrete floor with cinder block or concrete walls on three sides. Water liberated by the stored material will drain by gravity to the surge tank via a sump pump located at the storage area. From the open storage the combination ash material will be loaded into trucks and hauled to disposal.

A.7 FGD Sludge Handling System Unit 3

Scrubber sludge from the Unit 3 FGD system is sent to vacuum filters in the Sludge Conditioning Building for dewatering. The dry by-product filter cake is mixed with fly ash in pug mill mixers to create a conditioned FGD waste suitable for land disposal. The conditioned FGD sludge is transferred from the Sludge Conditioning Building to the landfill disposal area by a series of horizontal belt conveyors.

The paved ash haul and unpaved conditioned sludge haul roads will use water sprays and dust suppression chemicals for dust control.

II. EMISSION SUMMARY

1. Potential to Emit for Unit 3

Since Units 1 and 2 were previously permitted under a separate PSD permitting action and no creditable emissions increases or decreases are being relied on in this current permit application, the emissions increases for the Unit 3 project are based only on the potential to emit (PTE) of the new Unit 3.

All PSD thresholds are based upon "potential-to-emit (PTE)." For PSD applicability purposes only, this is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design after the application of air pollution control equipment and after considering all "federally enforceable" limitations restricting the potential-to-emit of the source.

A. Rationale for Determining Unit 3 PTE

The worst-case operating scenario PTE values for Unit 3 were obtained using assumptions on what a newly constructed Unit 3 could achieve through the application of control technology required pursuant to applicable NSPS and BACT for each pollutant under consideration. This includes the following assumptions:

Fuel and Unit Size:

- A nominal unit size of 950-MW (997.5.MW gross).
- A unit annual capacity factor of 100 percent
- An average maximum design coal sulfur content of 0.75 percent
- A design coal heating value of 11,193 Btu/lb

SO_2:

- The use of a forced oxidation wet limestone SO_2 scrubber system
- The SO_2 control system will be designed to meet 0.10 lb/MMBtu

NO_x:

- The use of LNBs, overfire air, and SCR control
- The NO_x control system will be designed to meet 0.07 lb/MMBtu

Total PM and PM_{10}:

- The use of a fabric filter baghouse
- The boiler baghouse control system will be designed to meet a filterable PM_{10} emission limit of 0.015 lb/MMBtu and PM 0.020 lb/MMBtu.
- The use of covered conveyors, dust suppression, and fabric filters
- Drift eliminators designed to achieve 0.0005 percent total liquid drift (0.000005 gal drift/gal flow) will be used to control PM_{10} emissions from the proposed cooling towers

CO:

- The use of good combustion controls to limit CO emissions

VOC:

- The use of good combustion controls to limit VOC emissions

Lead:

- The use of a fabric filter baghouse

H_2SO_4:

- The use of a forced oxidation wet limestone SO_2 scrubber system and fabric filters

Fluorides:

- The use of a forced oxidation wet limestone SO_2 scrubber system

TRS and RSC:

- The use of good combustion controls to limit TRS and RSC emissions

Summary of Unit 3 PTE

The Unit 3 emissions estimates include the Unit 3 boiler, the cooling towers, and different materials handling operations. Unit 3 has material handling operations for coal, fly ash, limestone preparation, WFGD sludge and ash disposal, and water treatment.

The major air emission sources and regulated air pollutants for Unit 3 are shown in the following the Table 1:

Table 1 Unit 3 Air Emission Sources and Regulated Air Pollutants

Source Number	Emission Point	Regulated Air Pollutants
Unit 3	Main Boiler – Unit 3 Stack	SO_2, NO_x, PM, PM_{10}, CO, VOC, Lead, H_2SO_4, Fluorides, TRS, RSC, HAPs
3A and 3B	Unit 3 Cooling Towers	PM, PM_{10}
F-17	Unit 3 Coal Pile – Fugitives	PM, PM_{10}
EP-12, EP-27, EP-28, EP-32,	Units 1, 2, and 3 Coal Handling System (Unit 3 portion only)	PM, PM_{10}

EP-33, EP-34, EP-35, EP-36, EP-97, EP-98, EP-99, EP-100, F-101A, EP-101B, EP-102, EP-103, EP-104, EP-105, and EP-106a		
EP-106b, EP-127, EP-128 and EP-129	Unit 3 Coal Handling System	PM, PM_{10}
EP-171 and EP-172	Unit 3 Fly Ash Handling	PM, PM_{10}
F-130, F-153, EP-155, EP-156, EP-157, EP-158, EP-190, EP-191, and EP-192	Units 1, 2, and 3 Limestone Handling (Unit 3 portion only)	PM, PM_{10}
F-137 and F-139	Unit 3 Limestone Pile – Fugitives	PM, PM_{10}
EU-29, EU-30, EU-31, and EU-32	Units 1, 2, and 3 Water Treatment (Unit 3 portion only)	PM, PM_{10}
EU-35	Unit 3 FGD Sludge Handling – Fugitives	PM, PM_{10}
	Unit 3 Ash Hauling – Fugitives	PM, PM_{10}
	Unit 3 Conditioned Sludge Hauling - Fugitives	PM, PM_{10}

A.1 Unit 3 Boiler PSD Pollutant Emissions

A summary of the post-project potential (PPP) to emit for Unit 3 is shown in the table below. These emission rates are the maximum expected emission rates based on continuous operation of the new unit. These maximum hourly emission rates were the basis for Unit 3 modeling and analysis of Air Quality Relating Values (AQRVs).

Table 1, Unit 3 Boiler stack worst-case annual operating scenario PTE PSD Emissions (controlled)

Pollutant	Hourly Emissions[a] (lbs/hr)	Daily Emissions[a] (lbs/day)	Annual Emissions[a b] (tpy)	PSD Significant Emission Levels (tpy)
SO_{2*}	905	21,720	3,963.9	40
NO_{x*}	633.5	15,204.0	2775	40

Total PM (filterable)	181.0	4,344.0	793	25
PM_{10*} (filterable)	135.7	3,256.8	595	15
PM_{10} *(filterable & condensable) [c]	220.9	5,301.6	968	15
CO*	1,357.5	32,580	5946	100
VOCs*(ozone)	24.3	583.2	107	40
Lead*	0.181	4.34	0.79	0.6
Mercury	0.00547	0.1315	0.024	0.1
H_2SO_4 [d]	39.7	952.8	174	7
Fluorides (as HF)	4.7	112.8	20.0	3
TRS	6.7	160.8	29	10
RSCs	6.7	160.8	29	10

[a] Hourly, daily, and annual emissions are estimated at 105-percent operating capacity for Unit 3.

[b] Based on a 30-day rolling average.

[c] Condensable PM_{10} includes hydrochloric acid (HCl), HF, H_2SO_4 and $(NH_4)_2SO_4$.

[d]Engineering estimates for H_2SO_4 are based on stack test results from Unit 1 adjusted to account for increases resulting from SCR operation on Unit 3
* Criteria Pollutants.

A.2 Unit 3 Boiler non-PSD Pollutant Emissions

The estimated worst-case operating scenario hourly and annual controlled emission rates of trace metal HAPs, organic HAPs, and acid gas HAPs are shown in Tables 3, 4, and 5, respectively. Best Available Control Technology (BACT) part of this review provides additional information on emissions estimates and control levels for the Section 112 HAPs.

Table 3, Unit 3 Boiler Trace Metal HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Antimony	0.01	0.02*
Arsenic	0.04	0.18*
Beryllium	0.00	0.002*
Cadmium	0.01	0.03*
Chromium	0.06	0.28*
Cobalt	0.01	0.03*
Lead	0.181	0.79
Manganese	0.03	0.15*
Mercury	0.00548	0.024***

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Nickel	0.03	0.13*
Selenium	0.23	1.02**

*AP-42 Table 1.1-16 (9/98)
** EPRI Coal HAP Report
*** Based on proposed MACT standard for Electric Utility Steam generating Units

Table 4, Unit 3 Boiler Organic HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Acenaphthene	0.00	0.00**
Acenaphthylene	0.00	0.00**
Acetaldehyde	0.23	1.01*
Acetophenone	0.01	0.03*
Acrolein	0.12	0.51*
Anthracene	0.00	0.00**
Benzene	0.03	0.15***
Benzo(a)anthracene	0.00	0.00**
Benzo(a)pyrene	0.00	0.00**
Benzo(b,j,k)fluoranthene	0.00	0.00**
Benzo(g,h,i)perylene	0.00	0.00**
Benzyl chloride	0.28	1.24*
Biphenyl	0.00	0.00**
Bis(2-ethylhexyl)phthalate (DEHP)	0.03	0.13*
Bromoform	0.02	0.07*
Carbon disulfide	0.05	0.23*
2-Chloroacetophenone	0.00	0.01*
Chlorobenzene	0.01	0.04*
Chloroform	0.02	0.10*
Chrysene	0.00	0.00**
Cumene	0.00	0.01*
2,4-Dinitrotoluene	0.00	0.00*
Dimethyl sulfate	0.02	0.08*
Ethyl benzene	0.04	0.17*
Ethyl chloride	0.02	0.07*
Ethylene dichloride	0.02	0.07*
Ethylene dibromide	0.00	0.00*
Fluoranthene	0.00	0.00**
Fluorene	0.00	0.00**
Formaldehyde	0.03	0.12***

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Hexane	0.03	0.12*
Indeno (1,2,3-cd) preen	0.00	0.00**
Isophorone	0.23	1.03*
Methyl bromide	0.06	0.28*
Methyl chloride	0.21	0.94*
5-Methyl chrysene	0.00	0.00**
Methyl ethyl ketone	0.16	0.69*
Methyl hydrazine	0.07	0.30*
Methyl methacrylate	0.01	0.04*
Methyl tert butyl ether	0.01	0.06*
Methylene chloride	0.12	0.51*
Naphthalene	0.01	0.02**
Phenanthrene	0.00	0.00**
Phenol	0.01	0.03*
Propionaldehyde	0.15	0.67*
Pyrene	0.00	0.00**
Tetrachloroethylene	0.02	0.08*
Toluene	0.01	0.06***
1,1,1-Trichloroethane	0.01	0.04*
Styrene	0.01	0.04*
Xylenes	0.01	0.07*
Vinyl acetate	0.00	0.01*
Total PCDD[a]/PCDF[b]	0.00	0.00***

[a] PCDD –polychlorinated dibenzo-p-dioxine
[b] PCDF – polychlorinated dibenzo furans
*AP-42 Table 1-1-14 (9/1998)
**AP-42 Table 1-1-13 (9/1998)
***EPRI Coal HAP Report

TABLE 5, Unit 3 Boiler Acid Gas HAPs

Pollutant	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Hydrogen Chloride	38.13	167.01*
Hydrogen Fluoride*	4.7	20

*Engineering Estimates

E. Unit 3 Cooling Towers

The worst-case operating scenario estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 cooling towers are shown in Table 6.

Table 6, Unit 3 Cooling Tower Particulate Emissions (Cooling Tower 3A& 3B)

Pollutant	Hourly Emissions[a, b] (lbs/hr)	Daily Emissions[a, b] (lbs/day)	Annual Emissions[a, b] (tpy)
Total PM	14.1	339.0	61.9
PM_{10}	0.7	16.9	3.1

[a] Based on the use of drift eliminators with total liquid drift of 0.000005 (gal drift/gal flow) and particulate distribution from "Calculating Realistic PM_{10} Emissions From Cooling Towers" paper presented at 2001 AWMA Annual Meeting, Chicago, Illinois.
[b] Hourly, daily, and annual emissions are estimated at 105-percent design capacity for Unit 3. The emissions are the total from cooling Towers 3A and 3B

F. Coal Handling

The worst-case operating scenario estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 Coal Handling System are shown in Tables 7, 8, and 9. The tables summarize particulate emissions. The emissions shown in Table 8 are for the estimated Unit 3 portion only. For common plant coal handling equipment, Unit 3 emissions were estimated to be 43.6 percent of the plant total based on the maximum coal burn rate for Unit 3.

Table 7, Unit 3 Coal Pile - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	0.01	0.24	0.04
PM_{10}	0.005	0.12	0.02

[a] AP-42 and Engineering Estimates
The emissions are the Unit 3 total from emission point F-17.

Table 8, Units 1, 2, and 3 Coal Handling System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	4.44	106.67	3.25
PM_{10}	2.10	50.45	1.54

[a] AP-42 and Engineering Estimates
Unit 3 estimated as 43.6 percent of the common coal handling transfer operations based on estimated coal received.
The emissions are the Unit 3 total from Emission Points EP-12, EP-27, EP-28, EP-32, EP-33, EP-34, EP-35, EP-36, EP-97, EP-98, EP-99, EP-100, EP-101A, EP-101B, EP102, EP-103, EP-104, EP-105, and EP-106a.

Table 9, Unit 3 Coal Handling System

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	0.09	2.18	0.10
PM_{10}	0.04	1.06	0.04

[a] AP-42 and Engineering Estimates

The emissions are Unit3 total from Emission Points EP-106b, EP-127, EP-128, and EP-129.

G. Unit 3 Fly Ash Handling

The worst-case operating scenario estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 fly ash handling system are shown in Table 10.

Table 10, Unit 3 Fly Ash Handling System

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	0.60	14.40	0.68
PM_{10}	0.30	7.20	0.34

[a] AP-42 and Engineering Estimates

The emissions are Unit3 total from Emission Points EP-171 and EP-172.

H. Unit 3 Limestone Handling

The estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 limestone handling system are shown in Tables 3-11 and 3-12. The tables summarize particulate emissions; details on each emission point can be found in Appendix C, Emissions Calculations. The emissions shown in Table 3-11 are for the estimated Unit 3 portion only. For the common plant limestone handling system, Unit 3 emissions were estimated to be 57.6 percent of the plant total based on the maximum limestone use rate for Unit 3.

Table 11

Units 1, 2, and 3 Limestone Handling System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/hr)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	1.88	45.07	0.27	AP-42 and Engineering Estimates
PM10	0.89	21.30	0.13	AP-42 and Engineering Estimates

Unit 3 estimated as 57.6 percent of the common limestone handling operations based on estimated limestone received.
The emissions are the Unit 3 total from Emission Points F-130, F-153, EP-155, EP-156, EP-157, EP-158, EP-190, EP-191, and EP-192.

TABLE 12
Unit 3 Limestone Pile – Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions (tpy)	Emission Factor Reference
Total PM	0.11	2.66	0.20	AP-42 and Engineering Estimates
PM10	0.10	2.30	0.16	AP-42 and Engineering Estimates

The emissions are the Unit 3 total Points F-137 and F-139

I. Unit 3 Water Treatment Plant

The worst-case operating scenario estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 water treatment system are shown in Table 13. The table summarizes particulate emissions. The emissions shown in Table 13 are for the estimated Unit 3 portion only. For the common plant water treatment system, Unit 3 emissions were estimated to be 33.4 percent of the plant total.

Table -13, Units 1, 2, and 3 Water Treatment System (Unit 3 portion only)

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions[a] (lbs/day)	Annual Emissions (tpy)
Total PM	0.000	0.005	0.000
PM_{10}	0.000	0.004	0.000

[a] AP-42 and Engineering Estimates
The emissions are Unit3 total from Emission Points EU-29, EU-30, and EU-32.

J. Unit 3 Sludge/Ash Handling and Hauling

The worst-case operating scenario estimated hourly, daily, and annual controlled particulate emission rates from the Unit 3 sludge/ash handling and hauling are shown in Tables 12, 13, and 14. The tables summarize particulate emissions.

Table 14, Unit 3 FGD Sludge Handling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	1.73	41.45	5.07
PM_{10}	1.58	37.90	4.63

[a]. AP-42 and Engineering Estimates
The emissions are Unit3 total from Emission PointsEU-35.

Table 15, Unit 3 Ash Hauling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	1.05	25.20	4.59
PM_{10}	0.20	4.80	0.89

[a] AP-42 and Engineering Estimates
Based on paved road emissions.

Table 14, Unit 3 Conditioned Sludge Hauling - Fugitives

Pollutant	Maximum Hourly Emissions (lbs/hr)	Maximum Daily Emissions (lbs/day)	Annual Emissions[a] (tpy)
Total PM	13.61	326.64	43.46
PM_{10}	3.54	84.96	11.30

[a] AP-42 and Engineering Estimates
Based on uppaved road emissions.

2. Pre-Project Actual Emissions

In determining pre-project actual (PPA) emissions values for Units 1 and 2, past actual emissions were established as the most recent two consecutive calendar years of 2000 and 2001. These 2 years were determined to be representative of normal operation and were used for establishing PPA emission values.

There have been no creditable emission increases or decreases during the period from 1999 through the projected construction commencement date of 2004 that have not otherwise been permitted with an AO.

Table 1 summarizes the PPA values used in determining the emission baseline requirement for the Unit 3 project. Past actual emissions are based on the average of actual emissions from 2000 and 2001. These 2 years are considered representative of normal operation.

Table 1, Unit 1 and 2 Total Actual Emissions 2000 and 2001

Pollutant	Unit 1 2000 Annual Emissions (tpy)	Unit 2 2000 Annual Emissions (tpy)	Unit 1 2001 Annual Emissions (tpy)	Unit 2 2001 Annual Emissions (tpy)	Units 1 and 2 2000/2001 Average Annual Emissions (tpy)
SO_2	1,855.1	1,619.2	1,914.1	2,286.2	3,837.3
NO_X	13,972.0	12,137.0	12,848.0	13,839.0	26,398.0
PM_{10}	223.4	100.5	83.0	74.3	240.6
CO	699.8	621.2	631.5	706.7	1,330.8
VOCs					12.7
Lead					0.09

The emissions associated with IPP Unit 3 addition will be as follows:

Pollutant	Actual Emissions tons/year	Requested PTE Increase tons/year	Actual to Potential Increase tons/year	Total PTE Emissions tons/year	
PM (filterable)	0.00	912.56	912.56	912.56	
PM_{10}(filterable)	0.00	617.15	617.15	617.15	
PM_{10}(filterable & condensable)	0.00	990	990	990	
SO_2	0.00	3,963.9	3,963.9		3,963.9
NO_x	0.00	2775	2775	2775	
CO	0.00	5946	5946	5946	
VOC	0.00	107	107	107	
H_2SO_4	0.00	174	174	174	
Lead	0.00	0.79	0.79	0.79	
Total Reduced Sulfur	0.00	29	29	29	
Reduced Sulfur Compounds	0.00	29	29	29	
HAPs					
HCL	0.00	167.01	167.01	167.01	
Fluorides /HF	0.00	20.00	20.00	20.00	
Mercury	0.00	0.024	0.024	0.024	
Total HAPs	0.00	199	199	199	

III. APPLICABILITY OF FEDERAL REGULATIONS AND UTAH ADMINISTRATIVE CODES (UAC)

This section presents a summary of applicable requirements relating to new Unit 3 sources or existing sources that will be modified to accommodate the Unit 3 changes.

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
Utah Administrative Code						
R307-101	General Requirements	Forward and definitions regarding UAC Title R307 Environmental Quality – Air Quality.		?	This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within R307.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-102-1	Air Pollution Prohibited Periodic Compliance Report Required	(1) "Air Pollution" is the presence in the ambient air of one or more air contaminants in such quantities and duration and under conditions and circumstances, as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or use of property as determined by the standards, rules, and regulations adopted by the Air Quality Board is prohibited. The state statute provides for penalties up to $50,000/day for violation of state statutes, regulations, rules, or standards. (2) The owner or operator of any stationary air contaminant source in Utah shall furnish to the Air Quality Board (Board) periodic reports as required under Section 19-2-104(1)(c) and any information the Board needs to determine compliance with the state and federal regulations and standards.	?		(1) Fines may be incurred if the facility is found in violation of state statutes, regulations, rules, or standards. (2) The facility is expected to submit information as required or requested by UDAQ.	(1) The facility shall monitor their emissions and practices to ensure that statutes, regulations, rules, or standards are not violated. (2) Representatives of the UDAQ or the Board will be allowed access to records, documents, or other sources of information as they request.
R307-102-2	Confidentiality of Information	Any person submitting information pursuant to these regulations may request that such information be treated as a trade secret or on a confidential basis.	?		No information in the application is confidential unless requested.	
R307-102-3.	Reserved			?	Reserved for later use by UDAQ.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-102-4	Variances Authorized	The Board may grant variance from these regulations unless prohibited by the CAA.		?	No variances are necessary for Unit 3 at this time. If a variance is needed in the future, a variance will be applied for and the proper documentation will be retained by IPSC.	
R307-102-5	No Reduction in Pay	Owners or operators may not temporarily reduce the pay of any employee by reason of the use of a supplemental or intermittent or other dispersion dependent control system for the purposes of meeting any air pollution requirement. Adopted pursuant to the CAA.		?	Unit 3 does not utilize dispersion-dependent control systems; therefore, this rule does not apply.	
R307-102-6	Emission Standards	Other provisions of R307 may require more stringent controls than listed herein, in which case those requirements must be met.	?			IPSC will comply with the most stringent provisions.
R307-103	Initial Orders and Notices of Violations (NOVs)	This rule outlines procedures for initial orders and NOVs.	?		IPP does not have any open orders or NOVs.	If IPP should ever receive a NOV or order, these rules will be followed.
R307-105	Emergency Controls	Defines the air pollution emergency episode criteria for criteria pollutants and outlines emergency actions required to be conducted by UDAQ.		?	This requirement applies to UDAQ and is not an obligation of IPSC.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-107	Unavoidable Breakdown	(1) Meet the reporting requirements specified in R307-107-2 in the event of an unavoidable breakdown: ?? Report breakdown to the executive secretary with in 3 hours (or to the Environmental Health Emergency Response Coordinator at 801-536-4123 if after office hours). ?? Submit a written report to the executive secretary with in 7 days that includes the cause and nature of the event, the estimated quantity of pollutant(s), the time of emissions, and the steps taken to control and prevent reoccurrence. (2) The owner or operator of an installation suffering an unavoidable breakdown shall assure that emission limitations and visible emission limitations are exceeded for only as short a period of time as reasonable.	?		Failure to meet reporting requirements can result in a violation. Immediate action must be taken to reduce emissions.	IPSC will provide all necessary reports to UDAQ in the time allotted. IPSC will take any steps to reduce emissions that do not jeopardize employee safety or equipment. Records will be retained at the plant.
R307-110	SIP	To meet requirements of the CAA, the Utah SIP must be incorporated by reference into these rules.		?	This requirement applies to UDAQ and is not an obligation of IPSC.	
R307-115	Determining Conformity	The Utah SIP must comply with 40 CFR Part 93, Subpart B Determining Conformity of General Federal Actions to State or Federal Implementation Plans which addresses transportation plans, projects, and programs in nonattainment areas.		?	IPSC is not located in a nonattainment area; therefore, this rule does not apply.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-120	Tax Exemption for Air and Water Pollution Control Equipment	Guidelines for receiving tax exemption for having pollution control equipment.		?	This does not pertain to the IPSC addition of Unit 3 because the equipment will be new. This rule offers tax exemptions to existing facilities to control current emissions only.	
R307-121	Vehicles that use Cleaner Burning Fuels	General Requirements: Eligibility of Expenditures for Purchase of Vehicles that Use Cleaner Burning Fuels or Conversion of Vehicles and Special Fuel Mobile Equipment to Use Cleaner Burning Fuels for Corporate and Individual Income Tax Credits.		?	IPSC has not converted vehicles or mobile equipment to cleaner burning fuel; therefore, this rule does not apply	
R307-122	Fireplaces and Wood Stoves that use Cleaner Burning Fuels	General Requirements: Eligibility of Expenditures for Purchase and Installation Costs of Fireplaces and Wood Stoves that Use Cleaner Burning Fuels.		?	IPSC has no fireplaces or wood stoves at this facility; therefore, this rule does not apply.	
R307-130	General Penalty Policy	Provides guidance to UDAQ for negotiating penalties for noncompliance.		?	This requirement applies to UDAQ and is not an obligation of IPSC.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-135	Enforcement Response Policy for Asbestos Hazard Emergency Response Act (AHERA)	Guidelines for penalty assessment for violation of the AHERA.		?	This applies only to educational facilities. IPSC is not an educational facility.	
R307-150	Emission Inventories – Applicability	Any Part 70 source shall submit an emission inventory report. Emission inventories are required every 3 years and are to be retained for at least 5 years.	?		IPP is subject to the permitting requirements of R307-415 and is therefore considered a Part 70 source.	IPP will complete, submit, and retain copies of emission inventories per the guidelines in this rule.
R307-155	HAP	The owner or operator of a Part 70 source that emits one or more HAPs shall submit a HAP inventory at the same time as the emission inventory and no later than April 15 of the year following.	?		IPP will be emitting one or more HAPs and will be required to submit a HAP inventory.	IPP will complete, submit, and retain copies of HAP emission inventories per the guidelines in this rule.
R307-158	Emission Statement Inventory	Emission statement inventories are required for some stationary sources in Salt Lake, Davis, Weber, and Utah counties and non-attainment areas for ozone.		?	IPP is not located in any of the mentioned counties nor is it located in a nonattainment area for ozone; therefore, this requirement does not apply.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-165	Emission Testing	Emission testing will be required of all sources with established emission limitation at least once every 5 years. Sources that have received an approval order will be tested within 6 months of startup in accordance with R307-401.	?		IPP is applying for an AO for the construction of Unit 3 and will need to comply with this rule.	At least 30 days prior to conducting any emission testing, the executive secretary will be notified of the date, time, and place of testing. Documentation of notifications and test results will be retained.
R307-170	Continuous Emission Monitoring Program	Any source required to install a CEMS to determine emissions to the atmosphere or to measure control equipment efficiency is subject to this rule. Section 7 of this rule provides guidance for conducting CEMS audits.	?		Facility will install a CEMS in accordance with R307-170-5 (general requirements) and R307-170-6 (1) Fossil Fuel Fired Steam Generators. Also see 40 CFR Part 75 in this table.	Submittal to UDAQ of an electronic data report including all required information.
R307-201-1	Emissions Standards	Listing of opacity requirements, compliance, and observation techniques.	?		Emissions from any source should not have greater than 20 percent opacity. Observations of stationary sources will be conducted in accordance with EPA Method 9.	Opacity observations will be conducted and documentation retained.

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-201-2	Automobile Emission Control Devices	Any person owning or operating any motor vehicle or motor vehicle engine registered in the State of Utah on which is installed or incorporated a system or device for the control of crankcase emissions or exhaust emissions in compliance with the federal motor vehicle rules, shall maintain the system or device in operable condition and shall use it at all times that the motor vehicle or motor vehicle engine is operated.	?			Vehicle maintenance records.
R307-201-3	Opacity for Residential Heating	This rule outlines requirements for visible emissions from residential solid fuel burning devices and fireplaces.		?	IPSC does not operate residential solid fuel burning devices or fireplaces at the plant; therefore, this rule does not apply.	
R307-202	Emissions Standards: General Burning	This rule describes open burning that is allowed with and without a permit in the State of Utah.	?		IPP does have a permit to conduct open burning for fire training	
R307-203	Emission Standards: Sulfur Content of Fuels	Any coal, oil, or mixture thereof, burned in any fuel burning or process installation not covered by NSPS for sulfur emissions shall contain no more than 1.0 pound sulfur per mmBtu heat input for any mixture of coal nor 0.85 pound sulfur per mmBtu heat input for any oil.		?	The coal-burning equipment at IPP is covered by NSPS; therefore, this rule does not apply.	
R307-204	Emission Standards: Smoke Management	This rule applies to persons using prescribed fire or wildland fire on land they own or manage.		?	IPP does not use prescribed or wildland fire on their property; therefore, this rule does not apply.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-205	Emission Standards: Fugitive Emissions and Fugitive Dust	Describes guidelines for controlling fugitive emissions and fugitive dusts but does not apply to any sources for which limitations for fugitive dust or fugitive emissions are assigned pursuant to R307-401, R307-305, or R307-307 nor to agricultural or horticultural activities.		?	Fugitive dust emissions from the IPP plant are assigned pursuant to R307-401 (NOI and AO); therefore, this rule does not apply.	
R307-206	Emission Standards: Abrasive Blasting	Emissions standards for abrasive cleaning sources.	?		IPSC conducts both confined and unconfined abrasive blasting on a regular basis.	
R307-210	NSPS	States that standards of performance for NSPS in 40 CFR 60 are incorporated into UAC. No description of requirements. Refer to 40 CFR 60 of this table for guidance.	?		See section for 40 CFR 60 (NSPS).	See section for 40 CFR 60 (NSPS).
R307-214	NESHAPs	States that standards of performance for NESHAPs in 40 CFR 61 and 40 CFR 63 are incorporated into UAC. No description of requirements. Refer to 40 CFR 61 and 40 CFR 63 of this table for guidance.	?		See sections for 40 CFR 61 and 40 CFR 63.	See sections for 40 CFR 61 and 40 CFR 63.
R307-215	Emission Standards: Acid Rain Requirements	States that standards of performance for 40 CFR 76 are incorporated into UAC. No description of requirements. Refer to 40 CFR 76 of this table for guidance.	?		See section for 40 CFR 76.	See section for 40 CFR 76.
R307-220	Emission Standards: Plan for Designated Facilities	Incorporates "designated facilities" that emit a "designated pollutant" to be subject to a standard of performance.		?	IPP is not a designated facility; therefore, this rule does not apply.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-221	Emission Standards: Emission Controls for Existing Municipal Solid Waste Landfills	Guidelines for existing municipal solid waste landfills.		?	Specific to designated facility mentioned; therefore, does not apply to IPP.	
R307-222	Emission Standards: Existing Incinerators for Hospital, Medical, Infectious Waste	Guidelines for existing incinerators for hospital, medical, and infectious waste		?	Specific to designated facility mentioned; therefore, does not apply to IPP.	
R307-223	Emission Standards: Existing Small Municipal Waste Combustion Units	Guidelines for existing small municipal waste combustion units.		?	Specific to designated facility mentioned; therefore, does not apply to IPP.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-301 to R307-343	Standards for Davis, Salt Lake, Utah Counties, and Nonattainment areas	These rules apply only to sources in nonattainment areas and specific counties.		?	IPP is not located in a nonattainment area or any of the counties listed; therefore, these rules do not apply	
R307-401-1 to R307-401-4	Permit: NOI and AO	Applies to any person intending to construct a new installation that will or might become an air pollution source.	?		Unit 3 will become an air pollution source.	This NOI is being submitted pursuant to this section.
R307-401-5	AO	Whenever the executive secretary determines that the NOI is in accord with applicable requirements, the executive secretary shall issue an order permitting the proposed construction, installation, modification, relocation or establishment, with the further stipulation that all required facilities be adequately and properly maintained. To accommodate staged construction of a large source, the executive secretary may issue an order authorizing construction of an initial stage prior to receipt of detailed plans for the entire proposal provided that the proposal is determined feasible by the executive secretary.	?		IPP cannot begin construction of Unit 3 until an AO is received or authorization is received from the executive secretary.	Authorization will be retained prior to construction and plans submitted according to this rule.

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-401-6	Conditions for Issuing AO	Stipulates that the executive secretary shall issue an approval order if all applicable requirements are met: (1) The degree of pollution control for emissions is at least BACT except as otherwise provided. (2) The proposed installation will be in accord with applicable requirements of: Utah Title R307; National Standards of Performance for New Stationary Sources; National Primary and Secondary Ambient Air Quality Standards; NESHAPs; NSR criteria; maximum allowable increase and maximum allowable concentration requirements for PSD; the SIP for the area, if the area is classified as a nonattainment or maintenance area; and new source requirements for nonattainment areas under the federal CAA.	?		Unit 3 will be constructed and operated in accordance with this section.	IPP will retain documentation of compliance on site.
R307-401-7	Temporary Relocation	The owner or operator of a source previously approved under R307-401 or in an SIP may temporarily relocate and operate the source at any site for up to 180 working days in any calendar year not to exceed 365 consecutive days, starting from the initial relocation date.		?	No sources at IPP have been, or are planned to be, temporarily relocated; therefore, this rule does not apply.	
R307-401-8	Nonattainment and Maintenance Areas	Additional requirements for sources in nonattainment and maintenance areas.		?	IPP is not located in a nonattainment or maintenance area; therefore, this rule does not apply.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-401-9	Relaxation of Limitations	At a time that a source or modification becomes a major source or major modification because of a relaxation of any enforceable limitation ... then the pre-construction requirements shall apply to the source as though construction had not yet commenced on the source or modification.		?	IPP is already a major source and Unit 3 will be a major modification; therefore, this section does not apply.	
R307-401-10	LNB Technology	Outlines requirements for addition of low NO_x technologies for existing sources.		?	Unit 3 is not a pre-existing installation; therefore, this section does not apply.	
R307-401-11	Eighteen Month Review	AOs shall be reviewed 18 months after the issue date to determine the status of construction, installation, modification, relocation, or establishment. If the program is not proceeding, the AO may be revoked.	?		If construction does not proceed, the AO can be revoked.	Construction of Unit 3 is scheduled to proceed within 18 months of approval from UDAQ.
R307-403	Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas	Limitations and offset requirements for sources in nonattainment and maintenance areas.		?	IPP is not located in a nonattainment or maintenance area; therefore, this rule does not apply.	
R307-405-1	Permits: Prevention of Significant Deterioration of Air Quality (PSD)	Forward and definitions regarding this section.	?		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within R307-405.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-405-2 to R307-405-5 and 7	PSD	Describes how UDAQ will designate areas as Class I, II, or III and sets maximum allowable increases in certain pollutants.		?	These are requirements for UDAQ and do not apply to IPP.	
R307-405-6	PSD Areas – New Sources and Modifications	Every new major source or major modification must be reviewed by the executive secretary to determine the air quality impact of the source.	?		The major modification portion of this rule does apply to fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtus per hour heat input.	This NOI will be submitted to the UDAQ in compliance with this rule.
R307-405-8	PSD – Banking of Emission Offset Credits in PSD Areas	Banking of emission offset credits in PSD areas will be permitted.		?	No credit will be banked for this project; therefore, this does not apply to IPP.	
R307-406	Visibility	R307-406-1(1) the executive secretary shall review any new major source or major modification proposed. Pre- or post-construction visibility monitoring may be required if there is an adverse impact on visibility in a mandatory Class I area.		?	Review of major sources is a requirement for UDAQ. IPP does not have any Class I areas nearby; therefore, there should be no additional monitoring required.	

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-410-2	Permits: Emissions Impact Analysis – Use of Dispersion Models	All estimates of ambient concentrations derived in meeting the requirements of R307 shall be based on appropriate air quality models, databases, and other requirements specified in 40 CFR Part 51, Appendix W, (Guideline on Air Quality Models). Where an EPA–approved guidance documents is inappropriate, the executive secretary may authorize the modification of the model or substitution of another model. In meeting the requirements of federal law, any modification or substitution will be made only with the written approval of the Administrator.	?		Air quality models used should be chosen from preferred or alternative air quality models listed in 40 CFR 51, or authorization must be received from the executive secretary.	IPP used EPA Guideline air pollution dispersion models to estimate ambient concentrations. Documentation of these activities will be maintained.
R307-410-3	Permits: Emissions Impact Analysis – Modeling of Criteria Pollutant Impacts in Attainment Areas	A new source in an attainment area with a total controlled emission rate per pollutant greater than or equal to SO_2 40 tpy, NO_x 40 tpy, PM_{10} - fugitive emissions 5 tpy, and fugitive dust PM_{10} - non-fugitive emissions or non-fugitive dust 15 tpy, CO as required under R307-405-6(2), and lead 0.6 tpy shall conduct air quality modeling, as identified in R307-410-2.	?		IPP Unit 3 is a new source in an attainment area and has an emission rate greater than the limits listed; therefore, air quality modeling is required.	Air quality modeling has been conducted in accordance with R304-410-2 (see above). Documentation will be retained.
R307-410-4	Permits: Emissions Impact Analysis – Documentation of Ambient Air Impacts for HAPs	A new source shall provide documentation of increases in emission of HAPs including estimated maximum pounds per hour emission rate increase, type of release, whether the release flow is vertically restricted or unrestricted, the maximum release duration in minutes per hour, the release height measured from the ground, the height of any adjacent building or structure, the shortest distance between the release point and any area defined as "ambient air" under 40 CFR 50.1(e) for each installation for which the source proposes an emissions increase and emission threshold value	?		IPP is required to include this information with this NOI.	Section 6.3 of this NOI includes this information

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-410-5	Permits: Emissions Impact Analysis – Stack Heights and Dispersion Techniques	The degree of emission limitation required of any source for control of any air contaminant to include determinations made under R307-401, R307-403, and R307-405, must not be affected by so much of any source's stack height that exceeds GEP or by any other dispersion technique except for certain stacks that were in existence prior to 1970 or 1974 (see UAC section for complete exception). This does not restrict, in any manner, the actual stack height of any source.	?		IPP, Unit 3 stack will not qualify for the exemption. GEP is expected to be approximately 750 feet (2.5 X 300 feet).	IPP will not model a stack height higher than GEP.
R307-413	Permits: Exemptions and Special Provisions	Describes exemptions to the NOI and permitting process.		?	IPP does not meet the criteria to qualify for an exemption.	
R307-414	Permits: Fees for AOs	The owner and operator of each new major source or major modification is required to pay a fee to the department sufficient to cover the reasonable costs of reviewing and acting upon the NOI.	?		IPP is aware of the fee process and is prepared to pay a base fee of $27,000 due with the submittal of this NOI, and additional charges of $60 per hour if the standard allotted hours are exceeded.	IPP will retain proof of payments on file.
R307-415	Permits: Operating Permit Requirements	Defines requirements and process of obtaining an operating permit.	?		IPSC obtained a Title V permit for Units 1 and 2 on January 9,1998, which was renewed 8/8/2003. This NOI requests a reopening to include Unit 3.	Permit was received and is retained in facility files.

Summary of Applicable Requirements – Utah Administrative Code

Citation	Description	Requirement/Standard	Applicable		Explanation/ Comments	Methods Used to Demonstrate Compliance
			Yes	No		
R307-417	Permits: Acid Rain Sources	The provisions of 40 CFR 72 for purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA, are incorporated into these rules by reference.	?		IPSC has already obtained a Title IV permit for Units 1 and 2 that is included as part of the Title V permit. IPSC will submit an acid rain permit application for Unit 3 separately.	Permit was received and is retained in facility files.
R307-420	Permits: Ozone Offset Requirements	Defines procedures for complying with standards when located in an ozone nonattainment area.		?	Applies to Davis and Salt Lake Counties only; therefore, does not apply to IPP.	
R307-801	Asbestos	This rule establishes procedures and requirements for asbestos projects and training programs, procedures, and requirements for the certification of persons engaged in asbestos activities, and work practice standards for performing such activities.		?	IPP does not engage in NESHAPs sized asbestos activities; therefore, this rule does not apply.	
R307-840	Lead-Based Paint	Rule R307-840 establishes procedures and requirements for the accreditation of lead-based paint activities training programs, procedures and requirements for the certification of individuals and firms engaged in lead-based paint activities, and work practice standards for performing such activities.		?	IPP does not engage in lead-based paint activities; therefore, this rule does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
Federal Requirements 40 CFR parts 1 through 49 List various requirenments for EPA to operate their environmental programs. These sections do not apply to IPP.					
40 CFR 50, National Primary and Secondary Ambient Air Quality Standards					
40 CFR 50	This part sets forth national primary and secondary ambient air quality standards.		?	These guidelines apply to the EPA; therefore, do not apply to IPP.	
40 CFR 51, Requirements For Preparation, Adoption, and Submittal of Implementation Plans					
40 CFR 51	This part outlines requirements for SIP.		?	These guidelines apply to states and are not requirements of IPP; however, definitions may apply when evaluating other applicable requirements.	
40 CFR 52, Approval and Promulgation of Implementation Plans					
40 CFR 52	This part sets forth the administrator's approval and disapproval of state plans and the administrator's promulgation of such plans or portions thereof.		?	This section is administrative and has no requirements pertaining to IPP or Unit 3.	
40 CFR 53, Ambient Air Monitoring Reference and Equivalent Methods					
40 CFR 53	This part guidelines monitoring reference and equivalent methods.		?	Requirements in this section apply to states; therefore, do not apply to IPP.	
40 CFR 54, Prior Notice of Citizen Suits					
40 CFR 54	Guidelines for citizens to file suits.		?	Requirements apply to citizens; therefore, do not apply to IPP.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 55, Outer Continental Shelf Air Regulations					
40 CFR 55	Guidelines and requirements for facilities on the outer continental shelf.		?	IPP is not located on the outer continental shelf; therefore, these rules do not apply.	
40 CFR 56, Regional Consistency					
40 CFR 56	This part applies to EPA employees.		?	IPP is not an EPA employee; therefore, these rules do not apply.	
40 CFR 57, Primary Nonferrous Smelter Orders					
40 CFR 57	Guidelines and requirements for smelters.		?	IPP does not operate a smelter; therefore, these rules do not apply.	
40 CFR 58, Ambient Air Quality Surveillance					
40 CFR 58	This part sets guidelines and requirements for PSD monitoring stations and air pollution control agencies.		?	IPP does not operate a PSD monitoring station nor is it an air pollution control agency; therefore, these rules do not apply.	
40 CFR 59, National VOC Emission Standards for Consumer and Commercial Products					
40 CFR 59	This part sets guidelines and requirements for consumer and commercial products.		?	IPP does not manufacture consumer or commercial products; therefore, these rules do not apply.	
40 CFR 60, Subpart A, General Provisions for Standards of Performance for New Sources					
40 CFR 60.1 – 60.4	Specifies applicability, definitions, units and abbreviations, and communication guidelines of 40 CFR 60.	?		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 60.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.5-60.6	Administrator determination of construction or modification.		?	This section applies to the EPA; therefore, it does not apply to IPP.	
40 CFR 60.7(a)	Notification, reporting and recordkeeping requirements for the affected units and the CEMS.	?		Notification must be sent to UDEQ of: the date construction is commenced (no more than 30 days after), the date of initial startup (no more than 15 days after), physical or operational changes that may increase emission rates (no less than 60 days before), the demonstration of the continuous monitoring system performance (no less than 30 days before), the date for conducting opacity observations (no less than 30 days before), COMS data results will be used to determine compliance with the opacity standard in lieu of Method 9 (no less than 30 days before).	Send required information to UDEQ, maintain copies on file.
40 CFR 60.7(b)	Owners or operators shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.	?		IPP is subject to NSPS, and therefore, to this requirement.	Records of these occurrences and subsequent agency notifications will be maintained on file.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.7(c) & (d)	Owners or operators required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report and/or summary report form semiannually.	?		Written reports shall include magnitude of excess emissions, conversion factors used, date and time of commencement process operating time, specific identification of each period of excess emissions, nature and cause of any malfunction, corrective action, dates and times when the continuous monitoring system was inoperative, or statement of no excess emissions. Reports will be sent within 30 days of the end of the 6 month period. Also see 40 CFR Part 75.	Reports should be completed and sent to UDEQ via certified mail. Copies should be maintained.
40 CFR 60.7(e)	Adjusts more frequent reporting requirements to the requirements above if the facility meets certain conditions.		?	This can only be accomplished after a minimum of 12 months of monitoring; therefore, this rule does not apply to IPP Unit 3 at this time.	
40 CFR 60.7(f) – (h)	Owners or operators shall maintain a file of all measurements; continuous monitoring system performance evaluations, calibration checks, adjustments, and maintenance in permanent form suitable for inspection.	?		Files shall be retained for at least 2 years. Note: 40 CFR Part 75 requires a minimum of 3 years retention.	Files shall be retained for at least 3 years.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.8	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup and at such other times as may be required by the administrator, the owner or operator shall conduct performance test(s) and furnish the administrator a written report of the results of such performance test(s)	?		Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart or as the administrator shall specify. Notice should be sent to the administrator at least 30 days prior. Adequate performing testing facilities will be provided. Each test will consist of 3 runs unless otherwise specified.	Copies of agency notifications and testing reports will be maintained on site.
40 CFR 60.9	Availability of information to the public regarding this source and permit.		?	This requirement is for the Administrator; therefore, does not apply to IPP.	
40 CFR 60.10	State Authority- States maintain their authority to impose stricter requirements than the federal regulations.		?	This is guidance for the states and does not apply directly to IPP.	IPP must comply with all applicable state regulations (see UAC sections of this table).
40 CFR 60.11	Performance tests shall determine compliance with standards in this part, except opacity standards which will be determined by conducting observations in accordance with Method 9, using an alternative method approved by the Administrator, or by implementing a COMS. Air pollution control equipment shall be maintained in a manner consistent with good air pollution control practice.	?		Opacity observations shall be conducted concurrently with the initial performance test, or within 60 days after achieving the maximum production rate if performance tests will not be conducted.	Required tests/observations should be recorded and retained on file.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.12	No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment, or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutents to achieve compliance with opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.	?		IPP should not use any device to conceal their emissions.	Maintain all building plans and equipment specifications to document compliance.
40 CFR 60.13(a), Appendix B (COMS)	COMS installed will meet ASTM 6216-98 and have a certificate of conformance from the manufacturer. COMS will be located where measurements are representative of the total emissions from the facility. All tests and re-tests will be conducted as outlined in 40 CFR 60 Appendix B.	?		Appendix B gives extensive requirements and specifications for COMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Verify and document that COMS meet ASTM 6216-98, retain certificate of conformance on file. Document all tests, re-test, and all other requirements given in Appendix B.
40 CFR 60.13(a), Appendix B (CEMS)	Procedures for measuring CEMS relative accuracy and calibration drift are outlined. CEMS installation and measurement location specifications, equipment specifications, performance specifications, and data reduction procedures are included. Conformance of the CEMS with the performance specification is determined.	?		Appendix B gives extensive requirements and specifications for CEMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Verify and document that CEMS meets requirements of this appendix. Document all tests, re-tests, and all other requirements given in Appendix B.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(a), Appendix F	This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the EPA. Source owners and operators responsible for one or more CEMS used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist. Data collected as a result of QA and QC measures required in this procedure are to be submitted to the EPA. These data are to be used by both the EPA and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.	?		Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities: 1. Calibration of CEMS. 2. CD determination and adjustment of CEMS. 3. Preventive maintenance of CEMS (including spare parts inventory). 4. Data recording, calculations, and reporting. 5. Accuracy audit procedures including sampling and analysis methods. 6. Program of corrective action for malfunctioning CEMS. These written procedures must be kept on record and available for inspection by the enforcement agency. Also see 40 CFR Part 75.	Procedures should be written, implemented, and maintained on file. Activities outlined in procedures should also be documented and records retained.
40 CFR 60.13(b)	CEMS will be installed and operational prior to performance tests. Manufacturer's written requirements or recommendations for installation operation and calibration shall be completed, as a minimum. If COMS data will be submitted, compliance with Performance Specification 1 (see 40 CFR 60 appendix B) must be met before the performance test.	?		Monitoring systems shall be operational and all necessary documentation completed before performance tests. Also see 40 CFR Part 75.	Document and retain records of installation and operational tests. Maintain records of manufacturer's requirements.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(c)	If the owner or operator of an affected facility elects to submit COMS data for compliance with the opacity, he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of this part before the performance test required under § 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or CEMS during any performance test required under § 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the administrator.	?		If COMS data will be submitted for compliance a performance evaluation will be completed before the performance test. Otherwise, performance evaluations shall be conducted during performance tests or within 30 days of performance tests. Also see 40 CFR Part 75.	Document performance evaluations and retain records.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.13(d)	Owners and operators of a CEMS installed in accordance with the provisions of this part, must automatically check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For continuous monitoring systems measuring opacity of emissions not using automatic zero adjustments, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments. For systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.	?		Owners and operators of COMS and/or CEMS must check the zero and span calibration drifts at least once daily in accordance with a written procedure. Adjustments will be made when necessary. Also see 40 CFR Part 75.	Write and implement a procedure for this requirement. Document all checks, calibrations, adjustments, and cleanings.
40 CFR 60.13(e) – (j)	Guidelines for adjustments, monitoring requirements, tests, and data requirements for CEMS and COMS are outlined in these paragraphs.	?		These paragraphs give extensive requirements and specifications for CEMS and COMS and should be referenced to verify compliance. Also see 40 CFR Part 75.	Compliance with all required activities should be documented and records retained.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.14	Any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.	?		Unit 3 is a new affected facility and is subject to NSPS.	This permit modification is being applied for by IPSC for the addition of Unit 3. Unit 3 will not be built until all necessary permits are obtained.
40 CFR 60.15	An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.		?	IPP is not planning any reconstruction at this time; therefore, this rule does not apply.	
40 CFR 60.16	Priority list for regulators.		?	The priority list is guidance for the regulators and does not apply to IPP.	
40 CFR 60.17	Incorporations by reference.	?		No specific requirements are presented in this section.	
40 CFR 60.18	This section contains requirements for control devices used to comply with applicable subparts of Parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.		?	The control devices used for Unit 3 are not covered by this section; therefore, this section does not apply to IPP.	
40 CFR 60.19	General notification and reporting requirements.	?		Refer to this section for details of all notification and reporting requirements.	All necessary reports will be submitted to UDAQ in the appropriate timeframe.
40 CFR 60.20-29	SIP guidance.		?	These sections give guidance for states and does not apply to IPP.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.30 – 60.39	These sections are specific to waste combustion units, incinerators, solid waste landfills, and sulfuric acid production plants.		?	IPP does not conduct any of the mentioned processes; therefore, these sections do not apply.	
40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971					
40 CFR 60.40-46	Each fossil-fuel-fired steam generating unit of more than 73 MW heat input rate (250 mmBtu per hour) for which construction is commenced after August 17, 1971. Excludes sources that are subject to Subpart Da.		?	Unit 3 is covered under subpart Da; therefore, subpart D does not apply.	
40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978					
40 CFR 60.40a	The affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 MW (250 million mmBtu per hour) heat input of fossil fuel (either alone or in combination with any other fuel); and for which construction or modification is commenced after September 18, 1978.	?		Unit 3 meets the criteria listed and must meet the requirements in this subpart.	No requirements mentioned in this section.
40 CFR 60.41a	Definitions for 40 CFR 60, Subpart Da.	?		This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements from Subpart Da.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.42a	On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain PM in excess of: (1) 13 ng/J (0.03 lb/mmBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel; (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and (3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel. (b) On and after the date the PM performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.	?		Unit 3 may not discharge in amounts greater than what is listed in this section.	EPA reference Method 5 will be used to demonstrate compliance with PM emission limit. All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify, and maintain a COMS.
40 CFR 60.43a	On and after the date on which the initial performance test is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel any gases which contain SO_2 in excess of 520 ng/J (1.20 lb/mmBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/mmBtu) heat input.	?		Unit 3 may not discharge in amounts greater than what is listed in this section. Both scrubber inlet and outlet SO_2 concentrations will be continuously monitored to determine removal efficiency.	All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify (Appendix B) and maintain (Appendix F) a CEMS for SO_2 and a diluent gas.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.44a	On and after the date on which the initial performance test is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average: Subbituminous coal – 210 (ng/J), 0.50 (lb/MMBtu) Bituminous coal – 260 (ng/J), 0.60 (lb/MMBtu) Anthracite coal - 260 (ng/J), 0.60 (lb/MMBtu) All other fuels – 260 (ng/J), 0.60 (lb/MMBtu). Also emissions of NOx shall not exceed 1.6 pounds per megawatt hour	?		Unit 3 may not discharge in amounts greater than what is listed in this section. Current plans call for the use of a blend of 80 percent bituminous, 20 percent subbituminous coal in Unit 3. Weighted average emission limits under this rule may require EPA approval.	All monitoring activities and/or reports of emissions should be documented and retained on file. IPP will install, certify (Appendix B) and maintain (Appendix F) a CEMS for NO_x and a diluent gas.
40 CFR 60.45a	An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.		?	No emerging technologies will be used for Unit 3; therefore, this section does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.46a	Compliance with PM and NO_x limits listed in 40 CFR 60.42 and 60.44 constitutes compliance for these pollutants. During emergency conditions in the principal company, an affected facility with a malfunctioning FGD system may be operated if SO_2 emissions are minimized by operating all operable FGD system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed, bypassing flue gases around only those FGD system modules that have been taken out of operation because they were incapable of any SO_2 emission reduction or which would have suffered significant physical damage if they had remained in operation, and designing, constructing, and operating a spare FGD system module for an affected facility larger than 365 MW (1,250 MMBtu per hr) heat.	?		If compliance with 40 CFR 60.42 or 60.44 can not be maintained, refer to this section for further guidance. If desulfurization system is malfunctioning, operate only if compliance with this section can be maintained.	Maintain documents illustrating compliance with 40 CFR 60.42 and 60.44. If compliance cannot be achieved or desulfurization system is malfunctioning, maintain documentation of activities required in this section.
40 CFR 60.47a	The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions and SO_2 and NO_x emissions discharged to the atmosphere. If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of Part 75 of this chapter and is continuing to meet the ongoing requirements of Part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49a.	?		IPP must have CEMS and must comply with this section.	Install CEMS and COMS and document calibration and maintenance of equipment, or comply with 40 CFR 75 and 60.49a.
40 CFR 60.48a	In conducting the performance tests required, the owner or operator shall use as reference methods and procedures in Appendix A of this part or the methods and procedures as specified in this section.	?		IPP must use these methods to conduct performance tests.	Document methods used to conduct tests.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 60.49a	For SO_2, NO_x, and PM emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the administrator.	?		IPP must submit these documents quarterly if electronic and semiannually if written, except when opacity limits are exceeded which must be submitted every quarter. Specific reporting requirements are listed in this section. Refer to section for specific requirements.	Submit required documents as outlined in this section.
40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units					
40 CFR 60.40b-end	PC-fired affected facilities having a heat input capacity greater than 29 MW (100 MMBtu/hour) and less than 73 MW (250 MMBtu/hour) and meeting the applicability requirements under Subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_x standards under this subpart and to the SO_2 standards under Subpart D (§ 60.43).		?	Subpart Db applies to boilers with heat input >100 MMBtu/hour and <250 MMBtu/hour; IPP Unit 3 is much larger. Therefore, this rule does not apply to Unit 3.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61, National Emission Standards For Hazardous Air Pollutants					
40 CFR 61.01 – 61.03	Definitions and general information regarding 40 CFR 61.	?		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 61.	
40 CFR 61.04	All requests, reports, applications, submittals, and other communications to the administrator pursuant to this part shall be submitted in duplicate to the appropriate regional office of the EPA to: Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, CO 80295. A copy should also be sent to: State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, UT 84116-0690.	?		All reports required under 40 CFR 61 shall be submitted to the listed addresses.	Maintain records of all submittals on file.
40 CFR 61.05	No owner or operator shall construct or modify any stationary source without first obtaining written approval from the administrator. No owner or operator shall operate a new stationary source in violation of standards, except under an exemption. Ninety days after the effective date of any standard, no owner or operator shall operate any existing source subject to that standard in violation of the standard, except under a waiver granted by the administrator or under an exemption granted by the President. No owner or operator subject to the provisions of this part shall fail to report, revise reports, or report source test results as required under this part.	?		IPP may not operate in violation of any applicable standards without a waiver or exemption. All reports required under this part shall be completed and sent to the appropriate regulatory agency as required.	Maintain all reports demonstrating compliance with regulations. Periodically audit internal procedures and practices to ensure compliance.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.06	Advises facilities that they can request a determination of construction or modification from the administrator.		?	It has already been determined that Unit 3 is considered a modification; therefore, this section does not apply.	
40 CFR 61.07	The owner or operator shall submit to the administrator an application for approval of the construction of any new source or modification of any existing source. The application shall be submitted before the construction or modification is planned to commence, or within 30 days after the effective date if the construction or modification had commenced before the effective date and initial startup has not occurred.	?		IPP must receive approval for the construction of Unit 3.	This NOI is being submitted for approval.
40 CFR 61.08	The administrator will notify applicant of approval.		?	This applies to the EPA and is not a requirement of IPP.	
40 CFR 61.09	The owner or operator of each stationary source which has an initial startup after the effective date of a standard shall furnish the administrator with written notification as follows: (1) A notification of the anticipated date of initial startup of the source not more than 60 days nor less than 30 days before that date. (2) A notification of the actual date of initial startup of the source within 15 days after that date.	?		IPP must send notification of anticipated and actual startup.	Maintain documentation that notification was sent on file.
40 CFR 61.10 – 61.11	Describes source reporting, waiver requests, and other requirements for existing sources.		?	Unit 3 is not an existing source; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.12	The owner or operator of each stationary source shall maintain and operate the source, including associated equipment for air pollution control, in a manner consistent with good air pollution control practice for minimizing emissions.	?		IPP must minimize emissions.	Implementation of BACT along with documentation of proper maintenance and monitoring should demonstrate compliance.
40 CFR 61.13 – 61.14	Each owner or operator shall conduct emission testing and maintain and operate each monitoring system as specified in applicable subparts.	?		IPP must complete requirements in applicable subparts. No new requirements mentioned in this section.	Maintain documentation of compliance with subparts.
40 CFR 61.15	Upon modification, an existing source shall become a new source for each HAP for which the rate of emission to the atmosphere increases and to which a standard applies.	?		Unit 3 constitutes a modification and must comply with this section.	HAPs discharged should be expressed in kg/hr. Emission factors should be from AP 42 or material balances, monitoring data, or manual emission tests if AP 42 does not satisfactorily demonstrate an increase or decrease.
40 CFR 61.20 – 61.26	Guidelines and requirements for uranium mines.		?	IPP does not operate any uranium mines on this property; therefore, these rules do not apply.	
40 CFR 61.30 – 61.34	Guidelines and requirements for facilities that process beryllium and beryllium compounds.		?	IPP does not process beryllium or beryllium compounds; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.40 – 61.44	Guidelines and requirements for rocket motor test sites.		?	IPP does not test rocket motors; therefore, these rules do not apply.	
40 CFR 61.50 – 61.56	Guidelines and requirements for facilities that process mercury ore to recover mercury, use mercury chloralkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge.		?	IPP does not have any processes that recover mercury or use mercury chloralkali cells, or incinerate dry sludge; therefore, these rules do not apply.	
40 CFR 61.60 – 61.71	Guidelines and requirements for facilities which produce ethylene dichloride by reaction of oxygen and hydrogen chloride with ethylene, vinyl chloride by any process, and/or one or more polymers containing any fraction of polymerized vinyl chloride.		?	IPP does not have any of these processes; therefore, these rules do no apply.	
40 CFR 61.90 – 61.97	Guidelines and requirements for operations at any facility owned or operated by the Department of Energy (DOE) that emits any radionuclide other than radon-222 and radon-220 into the air.		?	IPP is not owned or operated by the DOE; therefore, these rules do not apply.	
40 CFR 61.100 – 61.108	Guidelines and requirements for facilities owned or operated by any Federal agency other than the DOE and not licensed by the Nuclear Regulatory Commission that emits radionuclides into the air.		?	IPP is not owned or operated by any federal agency; therefore, these rules do not apply.	
40 CFR 61.110 – 61.112	Guidelines and requirements for facilities that have possible equipment leaks of benzene.		?	IPP does not have benzene in its processes; therefore, these rules do not apply.	
40 CFR 61.120 – 61.127	Guidelines and requirements for radionuclide emissions from elemental phosphorus plants.		?	IPP does not have any processes with elemental phosphorus; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.130- 61.139	Guidelines and requirements for furnace and foundry coke byproduct recovery plants.		?	IPP does not recover coke byproducts; therefore, these rules do not apply.	
40 CFR 61.140 – 61.157	Guidelines and requirements for facilities that manufacture, use, or handle asbestos.		?	IPP does not manufacture asbestos; therefore, these rules only apply to the handling of ACBM (if any) in the existing facility.	
40 CFR 61.160 – 61.165	Guidelines and requirements for glass manufacturing plants.		?	IPP does not manufacture glass; therefore, these rules do not apply.	
40 CFR 61.170 – 61.177	Guidelines and requirements for primary copper smelters.		?	IPP is not a copper smelter; therefore, these rules do not apply	
40 CFR 61.180 – 61.186	Guidelines and requirements for arsenic production facilities.		?	IPP is not a arsenic production facility; therefore, these rules do not apply.	
40 CFR 61.190 – 61.193	Guidelines and requirements for DOE facilities.		?	IPP is not a DOE facility; therefore, these rules do not apply.	
40 CFR 61.200 – 61.210	Guidelines and requirements for facilities with a phosphogypsum stack, or that otherwise use any quantity of phosphogypsum which is produced as a result of wet acid phosphorus production or is removed from any existing phosphogypsum stack.		?	IPP does not use phosphogypsum; therefore, these rules do not apply.	
40 CFR 61.220 – 61.226	Guidelines and requirements for sites that are used for the disposal of tailings, and that managed residual radioactive material during and following the processing of uranium ores.		?	IPP does not manage uranium or use its property for tailing disposal; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 61.240 – 61.247	Guidelines and requirements for sources that are intended to operate in volatile hazardous air pollutant (VHAP) service.		?	IPP does not have any sources intended to operate in (VHAP) service; therefore, these rules do not apply.	
40 CFR 61.250 – 61.256	Guidelines and requirements for facilities licensed to manage uranium byproduct materials during and following the processing of uranium ores, commonly referred to as uranium mills and their associated tailings. This subpart does not apply to the disposal of tailings.		?	IPP does not manage any uranium materials; therefore, these rules do not apply.	
40 CFR 61.270 – 61.277	Guidelines and requirements for facilities that store benzene.		?	IPP does not store benzene; therefore, these rules do not apply.	
40 CFR 61.300 – 61.306	Guidelines and requirements for benzene transfer operations.		?	IPP does not have any benzene transfer operations; therefore, these rules do not apply.	
40 CFR 61.340 – 61.358	Guidelines and requirements for chemical manufacturing plants, coke byproduct recovery plants, petroleum refineries or hazardous waste treatment, storage, and disposal facilities (TSDFs) that accept wastes from the previously mentioned plants.		?	IPP does not apply as any of the plants listed; therefore, these rules do not apply.	
40 CFR 62, Approval and Promulgation of State Plans for Designated Facilities and Pollutants					
40 CFR 62	This part sets forth the administrator's approval and disapproval of state plans for the control of pollutants and facilities.		?	This is the responsibility of the states and the administrator and does not apply to IPP.	
40 CFR 63, National Emission Standards for Hazardous Air Pollutants for Source Categories					

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.1 - 63.3	Definitions and general information regarding 40 CFR 63.	?		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 63.	
40 CFR 63.4	No owner or operator subject to the provisions of this part may operate any affected source in violation of the requirements of this part. No owner or operator subject to the provisions of this part shall fail to keep records, notify, report, or revise reports as required under this part.	?		IPP will not operate in violation of this part and will maintain records as required.	Record activities showing compliance and maintain on file.
40 CFR 63.5	No person may, without obtaining written approval in advance from the administrator do any of the following: construct a new affected source that is major-emitting and subject to such standard; reconstruct an affected source that is major-emitting and subject to such standard; or reconstruct a major source such that the source becomes an affected source that is major-emitting and subject to the standard	?		IPSC must receive approval before constructing Unit 3.	This NOI is being submitted in compliance with this rule.
40 CFR 63.6	The owner or operator of an affected source must develop and implement a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the source during periods of startup, shutdown, and malfunction; a program of corrective actions for malfunctioning process; and air pollution control and monitoring equipment used to comply with the relevant standard. This plan must be developed by the source's compliance date for that relevant standard.	?		IPSC must implement a startup, shutdown, and malfunction plan as described in this rule.	Maintain a copy of this plan on file.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.7	If required to do performance testing by a relevant standard, and a waiver of performance testing is not obtained, the owner or operator of the affected source must perform such tests within 180 days of the compliance date for such source.	?		IPSC must complete all required performance testing within 180 days of the compliance date.	Document the date all applicable tests are conducted and maintain on file.
40 CFR 63.8	The owner or operator of an affected source shall maintain and operate each continuing monitoring system (CMS) in a manner consistent with good air pollution control practices. All CMS must be installed such that representative measures of emissions or process parameters from the affected source are obtained. In addition, CEMS must be located according to procedures contained in the applicable performance specification(s). All CMS shall be installed, operational, and the data verified as specified in the relevant standard either prior to or in conjunction with conducting performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system. Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all CMS, including COMS and CEMS, shall be in continuous operation and shall meet minimum frequency of operation requirements.		?	Although Unit 3 will be equipped with a COMS and a CEMS, pursuant to the federal NSPS and acid rain programs, continuous monitoring is not required under NESHAP.	
470 CFR 63.9	The owner or operator of a source shall notify the administrator of the designated state authority if emissions increase, if a source will be constructed or reconstructed, and other notifications regarding CMS mentioned in 40 CFR 75.	?		This NOI is being submitted in accordance with this rule. IPSC will need to notify the state if changes are made to operations that affect emissions.	This NOI is being submitted in accordance with this rule.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.10	The owner or operator of an affected shall submit reports to the delegated state authority. In addition, if the delegated authority is the state, the owner or operator shall send a copy of each report submitted to the state to the appropriate regional office of the EPA, as specified in paragraph (a)(4)(i) of this section. The regional office may waive this requirement for any reports at its discretion.	?		Records shall be maintained of the occurrence and duration of each startup, shutdown, or malfunction of operation; the occurrence and duration of each malfunction of the required air pollution control and monitoring equipment; all required maintenance performed on the air pollution control and monitoring equipment; actions taken during periods of startup, shutdown, and malfunction when such actions are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan; all information necessary to demonstrate conformance with the affected source's startup, shutdown, and malfunction plan when all actions taken during periods of startup, shutdown, and malfunction are consistent with the procedures specified in such plan; each period during which a CMS is malfunctioning or inoperative; and all required measurements needed to demonstrate compliance with a relevant standard.	These records will be created and maintained on file.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.11	Owners or operators using flares to comply with the provisions of this part shall monitor these control devices to assure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators using flares shall monitor these control devices.		?	Flares will not be used as control devices; therefore, this rule does not apply.	
40 CFR 63.12 – 63.15	General information, authority delegation, and addresses pertaining to 40 CFR 63.	?		These are not applicable standards or limitations; however, these sections do apply when evaluating other applicable requirements within 40 CFR 63.40 – 63.44.	
40 CFR 63.40	The requirements of this subpart apply to any owner or operator who constructs or reconstructs a major source of HAPs after the effective date of Section 112(g)(2)(B) and the effective date of a Title V permit program in the state or local jurisdiction in which the major source is located unless the major source in question has been specifically regulated or exempted from regulation, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction.	?		Coal and oil fired power plants have been included in the 112(c) listing of source categories since December, 2000; therefore, this section does apply to Unit 3.	
40 CFR 63.41	Definitions applicable to 40 CFR 63.40 – 63.44.	?		This is not an applicable standard or limitation; however, this section will apply when evaluating other applicable requirements within 40 CFR 63.40 – 63.44.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.42	Program requirements governing construction or reconstruction of major sources. The anticipated promulgation date for a MACT standard for PC-fired power plants is December 2004; therefore, a case-by-case MACT standard must be proposed and implemented by UDAQ.	?		This rule applies to UDAQ and is not an obligation of IPP. However, IPP must comply with standards required by UDAQ.	
40 CFR 63.43	The requirements of this section apply to an owner or operator who constructs or reconstructs a major source of HAP subject to a case-by-case determination of MACT.	?		IPP must request approval of case-by-case MACT determinations.	This NOI contains Section 6, its tables and/or appendices that requests a MACT determination and provides all necessary documents.
40 CFR 63.44	Requirements for constructed or reconstructed major sources subject to a subsequently promulgated MACT standard or MACT requirement.		?	There are no promulgated MACT standards or requirements for coal fired power plants at this time; therefore, this section does not apply.	
40 CFR 63.50 – 63.56	This section implements Section 112(j) of the CAA and includes the "MACT Hammer". In general, permitting authorities must issue or reopen Title V permits when a source becomes subject to Section 112(j).	?		IPP already has a Title V permit, which does not address the Section 112(j) requirements and the plant became subject to Section 112(j) in December, 2000. Therefore, the provisions of 40 CFR 63.52 (b) apply to Unit 3.	Request for case-by-case MACT determination included in Section 6 of this NOI
40 CFR 63.60 – 63.62	Deletion and redefinition of specific chemicals on the HAPs list.		?	This is not an applicable standard or limitation.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 63.70 – 63.5779	MACT regulations pertaining to specific industries.		?	PC-fired boilers are not included in these sections; therefore, these rules do not apply to IPP or Unit 3.	
40 CFR 64, Compliance Assurance Monitoring					
40 CFR 64	Compliance Assurance Monitoring.	?		IPP is subject to federal acid rain program and is thus exempt from Part 64, pursuant to 40 CFR 64.2(b)(1)(iii) for the acid rain requirements only. A CAM plan will be required for particulate.	The CAM Plan for Unit 3 is contained in Section 9 of the NOI text.
40 CFR 65, Consolidated Federal Air Rule					
40 CFR 65	The provisions of this subpart apply to owners or operators expressly referenced to this part from a subpart of 40 CFR Parts 60, 61, or 63 for which the owner or operator has chosen to comply with the provisions of this part as an alternative to the provisions in the referencing subpart.		?	IPP is not seeking alternate compliance provisions in accordance with this rule; therefore, these rules do not apply.	
40 CFR 66, Assessment and Collection of NonCompliance Penalties by EPA					
40 CFR 66	Applies to all proceedings for the assessment by EPA of noncompliance penalties.		?	Requirements for the EPA, not an obligation of IPP.	
40 CFR 67, EPA Approval of State NonCompliance Program					
40 CFR 67	Standards and procedures under which EPA will approve state programs for administering the noncompliance penalty program.		?	EPA's requirements for states to implement a noncompliance penalty program, not an obligation of IPP.	
40 CFR 68, Chemical Accident Prevention Provisions					

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 68	This part sets forth the list of regulated substances and thresholds, gives the petition process for adding or deleting substances to the list of regulated substances, outlines who need a Risk Management Plan (RMP), and sets requirements for RMPs.	?		IPSC does not currently have any chemicals onsite in excess of their threshold quantity listed in 40 CFR 68.130. IPSC will evaluate the ammonia storage requirements associated with the SCR system on Unit 3 to determine whether the RMP program is triggered.	To be determined (TBD)
40 CFR 69, Special Exemptions From the Requirements of the Clean Air Act					
40 CFR 69	Lists special exemptions		?	IPP is not eligible for any special exemptions for the CAA.	
40 CFR 70, State Operating Permit Program					
40 CFR 70	The regulations in this part provide for the establishment of comprehensive state air quality permitting systems consistent with the requirements of Title V of the CAA. These regulations define the minimum elements required by the CAA for state operating permit programs and the corresponding standards and procedures by which the administrator will approve, oversee, and withdraw approval of state operating permit programs.	?		IPP already has a Title V permit, which will need to be revised to add the applicable requirements for Unit 3.	This NOI is being submitted as required for modifications.
40 CFR 71, Federal Operating Permit Programs					
40 CFR 71.1 – 71.23	Specifies applicability, definitions, units and abbreviations, and general guidelines of 40 CFR 71.	?		The State of Utah has been delegated authority to implement a federal operating permit pursuant to 40 CFR 70. Therefore, 40 CFR 71 requirements are not applicable requirements for this facility.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 71.24	Identifies where a permit application should be filed and outlines the following information that a permit application should contain to be complete: Identifying information, All information required in § 63.74 A statement of the proposed alternative emission limitation for HAPs from the early reductions source on an annual basis, reflecting the emission reductions required to qualify the early reductions source for a compliance extension Additional emission limiting requirements which are necessary to assure proper operation of installed control equipment and compliance with the annual alternative emission limitation for the early reductions source; Information necessary to define alternative operating scenarios for the early reductions source or permit terms and conditions for trading hazardous air pollutant increases and decreases. Statements related to compliance.	?		This NOI must comply with the requirements in this section.	This NOI was written in compliance with this section (see Completeness Checklist following Executive Summary).
40 CFR 71.25 – 71.27	Administrative guidelines on what a permit should contain; issuance, reopenings, and revisions; and public comment periods	?		These rules apply to the permitting authority and are not an obligation of IPP.	
40 CFR 72 Permits Regulation					
40 CFR 72.1-72.5	General provisions of the acid rain program. 40 CFR 72.9 specifies the standard permitting, monitoring, SO_2, NO_x, excess emissions, recordkeeping and reporting, and liability requirements for affected sources.	?		These sections do not include applicable standards or limitations; however, these definitions do apply when evaluating other applicable requirements in 40 CFR 72.	Maintenance of records.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.6	Defines facilities and units to which 40 CFR 72 apply.	?		Unit 3 is a new utility unit; therefore, these rules do apply.	
40 CFR 72.7 & 72.8	Outlines exemptions from these rules.		?	IPP does not qualify for any exemptions.	
40 CFR 72.9	Specifies that all facilities to which these rules apply must have an acid rain permit.	?		Separate EPA forms should be downloaded, filled out, and submitted to the EPA. The first step is to get an ORIS number assigned. Then the complete package of forms, which identify the DR and the ORIS number goes to the EPA.	Copies of IPSC's acid rain permit revision application will be submitted to EPA and UDAQ; a copy will be kept on file at the IPP.
40 CFR 72.10 - 72.13	Definitions and general information regarding 40 CFR 72.	?		These are not applicable standards or limitations; however, these definitions do apply when evaluating other applicable requirements within 40 CFR 72.	
40 CFR 72.20	Each affected source, including all affected units at the source, shall have one and only one designated representative, with regard to all matters under the acid rain program concerning the source or any affected unit at the source.	?		IPP must have one and only one representative for issues concerning the acid rain program.	IPP will specify one representative, and maintain the certificate listing the representative on file.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.21	In each submission required to by signed by the designated representative under the acid rain program, the designated representative shall certify, by signature: "I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made" and "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment." The representative will provide a copy of the submission or determination to the owners and operators.	?		The designated representative must have the quoted certifications on all documents being submitted or they will not be accepted by the regulatory agency. Owners and operators should be kept informed of submissions and other activities pertaining to these rules.	Documentation of submissions including certification should be kept on file. Documentation of updates to owners / operators should be kept on file (e.g., management review minutes).
40 CFR 72.22	The certificate of representation may designate one and only one alternate designated representative, who may act on behalf of the designated representative.	?		One alternate representative may be chosen to act in place of the designated representative.	Procedures for choosing an alternate and certification of the alternate should be maintained.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.23	The designated representative, alternate designated representative, and owners or operators may be changed at any time upon receipt by the administrator of a superseding complete certificate of representation. A superseding certificate must be received within 30 days of a change in owner or operator.	?		When any of these individuals change, a new certificate must be received.	All representatives and owners / operators must be listed on the most current certificate and certificates retained.
40 CFR 72.24	Requirements for a complete certificate of representation.	?		Specific and extensive requirements. See 40 CFR 72.24 for list of all applicable requirements.	Each certificate of representation issued will contain all required elements and will be retained on file.
40 CFR 72.25	Once a complete certificate of representation has been submitted in accordance with § 72.24, the administrator will rely on the certificate of representation unless and until a superseding complete certificate is received by the administrator.	?		IPSC must submit a new certification to change representatives.	IPSC will wait to change representatives until a new certificate has been issued whenever possible.
40 CFR 72.30 – 72.33	The designated representative of any source with an affected unit shall submit a complete the acid rain permit application by the applicable deadline in paragraphs (b) and (c) of this section, and the owners and operators of such source and any affected unit at the source shall not operate the source or unit without a permit that states its acid rain program requirements.	?		IPSC will need to update their current acid rain permit to accommodate the addition of Unit 3.	Current permit for the IPP facility will be retained on file. Copies of the acid rain permit application for Unit 3 will be submitted to UDAQ and will be kept on file at IPSC.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.40	Outlines the requirements of a complete compliance plan.	?		IPSC will need to create a complete compliance plan in accordance with this section.	A copy of the compliance plan will be submitted to EPA and UDAQ. IPSC will implement and maintain a compliance plan on site.
40 CFR 72.41 – 72.44	Guidelines for substitution plans, extension plans, reduced utilization plans, and repowering extensions.		?	IPSC is not conducting any of the activities required for these plans; therefore, these rules do not apply at this time.	
40 CFR 72.50 – 72.74	Guidelines for obtaining a Title IV permit.		?	IPP is not receiving a new permit, but is modifying a current permit. The provisions of 40 CFR 72.50 through 72.74 are applicable to initial permits. Modifications to existing permits are provided in 40 CFR 72.80 through 72.85.	
40 CFR 72.80	A permit revision may be submitted for approval at any time. No permit revision shall affect the term of the acid rain permit to be revised. No permit revision shall excuse any violation of an acid rain program requirement that occurred prior to the effective date of the revision.	?		IPSC must revise its permit to accommodate Unit 3.	Copies of the acid rain permit revision application will be submitted to EPA and UDAQ; kept on file at IPSC.
40 CFR 72.81	Permits must be revised if processes are modified	?		IPP must revise their permit to accommodate for the addition of Unit 3.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 72.82	The designated representative shall serve such a copy on the administrator, the permitting authority, and any person entitled to receive a written notice of a draft permit under the approved state operating permit program. Within 5 business days of serving such copies, the designated representative shall also give public notice by publication in a newspaper of general circulation in the area where the sources are located or in a state publication designed to give general public notice.	?		If IPP submits a fast-track modification, this rule will need to be adhered to.	Copies will be submitted to EPA and UDAQ; kept on file at IPSC. Retain documentation of public notice on file.
40 CFR 72.83 – 72.85	Administrative instructions for permit amendments and re-openings.	?		Administrative guidelines and requirements apply to permitting authority and are not an obligation of IPSC.	
40 CFR 72.90 – 72.96	For each calendar year in which a unit is subject to the acid rain emissions limitations, the designated representative of the source at which the unit is located shall submit to the administrator, within 60 days after the end of the calendar year, an annual compliance certification report for the unit.	?		IPP will need to submit an annual compliance certification as long as it is required to have an acid rain permit. Specific requirements for certification are detailed in this part.	Submit certification annually, retain copies on file.
40 CFR 73, Sulfur Dioxide Allowance System					
40 CFR Part 73	SO_2 allowance system.	?		The plant must have sufficient allowances available to account for each ton of annual SO_2 emissions. IPP already has sufficient credits to account for the increase of SO_2 emissions; therefore, no additional allowances will be needed.	CEMS and quarterly EDRs (pursuant to 40 CFR Part 75)

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 74, Sulfur Dioxide Opt-Ins					
40 CFR 74	Guidelines for Sulfur Dioxide Opt-In program.		?	IPSC is not eligible for the Opt-In program; therefore, these rules do not apply.	
40 CFR 75 Continuous Emission Monitoring					
40 CFR 75.1 – 75.3	Definitions and general information regarding 40 CFR 75.	?		This is not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements.	
40 CFR 75.4	The owner or operator of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO_2, NO_x, CO_2 opacity, and volumetric flow are installed and all certification tests are completed no later than 90 days after the date the unit commences commercial operation.	?		IPSC must install applicable monitoring equipment within specified time.	Retain documentation of installation and certification testing on file, suitable for agency inspection, for a minimum of 10 years.
40 CFR 75.5	Prohibitions – these rules clarify a variety of acts, omissions, or other events that constitute a violation of the CAA, relative to the acid rain monitoring provisions in Part 75.	?			Quarterly EDRs, periodic inspection of CEMS Monitoring Plans.
40 CFR 75.6	Incorporates several ASTM, ASME, and other methods by reference.		?	Not an applicable standard or limitation; however, information does apply when evaluating other applicable requirements.	
40 CFR 75.10	The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a continuous emission monitoring system for SO_2, NO_x, and CO_2,volumetric stack flow and opacity.	?		Specific requirements in this part. Refer to full text of rule.	Retain records of all activities specified.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.11 – 75.14	Specific provisions for monitoring SO_2, NO_x and CO_2 emissions, stack diluent (O2 or CO_2), stack flow, and opacity.	?		Specific and extensive provisions. IPSC will ensure that CEMS meet these requirements.	CEMS Monitoring Plan (required under §75.53) and CEMS certification report. Retain records of all activities specified.
40 CFR 75.15	Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology. This generally applies to units in existence during calendar years 1997 through 1999.		?	The SO_2 removal system planned for Unit 3 does not meet the definition of a qualifying Phase I technology. Therefore, this rule does not apply.	
40 CFR 75.16	Special provisions for monitoring SO_2 emissions from (and determining heat input for) common, bypass, and multiple stacks.		?	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	
40 CFR 75.17	Special provisions for monitoring NO_x from common, bypass, and multiple stacks.		?	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	
40 CFR 75.18	Special provisions for monitoring opacity from common and bypass stacks.		?	The generating units at IPP (including Unit 3) have separate stacks. Therefore, this rule does not apply.	
40 CFR 75.19	Optional SO_2, NO_x, and CO_2 emissions calculation for low mass emission units.		?	PC-fired boilers do not qualify as low mass emission units. Therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.20	The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part meets the initial certification and recertification requirements of this section and shall ensure that all applicable initial certifications and recertifications are completed by the deadlines specified.	?		Initial certification tests must be conducted for all CEMs, in accordance with this section and Appendix A of this Part.	Copies of initial certification and recertification testing reports will be submitted to EPA and UDAQ, retained on file at IPSC. Retain records of all certification tests and activities.
40 CFR 75.21	Details quality control and quality assurance requirements.	?		The CEMS must be operated and maintained in accordance with this section and Appendix B of this part.	Retain records of all QA/QC activities specified.
40 CFR 75.22	Reference test methods.	?		Identifies the EPA Reference Test Methods (provided in Appendix A of 40 CFR Part 60) that shall be used for certification tests, calibrations, and other measurements.	Certification and periodic audit reports will be retained on file at IPSC.
40 CFR 75.23	Alternatives to standards incorporated by reference.		?	IPSC has no plans to petition the administrator for an alternative to any standard incorporated by reference, pursuant to §75.66(c).	
40 CFR 75.24	Out-of-control periods and adjustment for system bias.	?		Out-of-control periods can be declared, based on daily calibration, quarterly audit, or linearity check results. During these periods, the data is considered not QA'd and shall not be used in calculating monitor availability.	QA/QC information transmitted with quarterly EDR.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.30 – 75. 37	Subpart D – missing data substitution procedures.	?		This subpart provides extensive guidance and requirements for substituting a variety of empirically-derived emissions values, which are usually much higher than actual emissions, during periods when the CEMS does not accurately measure SO_2, NO_x, CO_2, heat input, and moisture.	Substituted data are identified in the quarterly EDR.
40 CFR 75.40 – 75.48	Guidelines for using an alternative monitoring system, which must have the same or better precision, reliability, accessibility and timeliness as that provided by a CEMS meeting the requirements of this part.		?	IPP will not use alternative monitoring system; therefore, these rules do not apply.	
40 CFR 70.53	Specific guidelines and requirements for CEMS Monitoring Plans.	?		These provisions are very specific and extensive. Refer to full text of rule.	Monitoring plan submittal, pursuant to §75.62.
40 CFR 75.54	General recordkeeping provisions.		?	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore this rule does not apply.	
40 CFR 75.55	Recordkeeping provisions for specific situations.		?	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore this rule does not apply.	
40 CFR 75.56	Certification, QA/QC record provisions.		?	This rule applies to facilities in existence prior to 04/01/2000. Unit 3 will be constructed after that date; therefore, this rule does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.57	General recordkeeping provisions.	?		These provisions are very specific and extensive. Refer to full text of rule. All records of measurements, data, reports and other information required under Part 75 shall be maintained in a file at the plant, suitable for agency inspection, for a minimum of 3 years.	CEMS records on file at the plant, available for EPA/UDAQ inspection.
40 CFR 75.58	General recordkeeping provisions for specific situations.		?	This section provides recordkeeping provisions for alternative or parametric monitoring allowed for gaseous or liquid fuel-fired units only. Unit 3 is PC-fired; therefore this rule does not apply.	
40 CFR 75.59	Certification, QA/QC record provisions.	?		These provisions are very specific and extensive. Refer to full text of rule.	CEMS Monitoring Plan, quarterly EDRs, certification reports, RATA test reports, CEMS O&M records maintained at IPP.
40 CFR 75.60	Reporting requirements – general provisions.	?		This section details the schedules and criteria for the submittal of initial certification reports, recertification reports, monitoring plans, EDRs, RATA reports and other communications. In addition, provisions governing the confidentiality of data are provided.	Copies of these submittals will be kept on file at the plant for a minimum of 3 years.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.61	Reporting requirements – notifications.	?		This section details the schedules and criteria for notifying the EPA and UDAQ of planned testing dates, installation of new units, retiring units, changes in fuels used, or monitoring system components.	Records of notifications will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.62	Monitoring plan submittals.	?		This section details the schedules and criteria for submittal of the electronic and hardcopy CEMS monitoring plan, including any revisions to the monitoring plan.	Records of the monitoring plan submittals will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.63	Initial certification or recertification application submittals.	?		This section details the schedules and criteria for the submittal of initial certification reports and recertification applications.	Records of the certification and recertification submittals will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.64	Quarterly electronic data reports.	?		This section details the content and submittal format requirements for the submission of CEMS measurements data, along with a variety of QA/QC activities and results for the preceding calendar quarter. Each EDR is due on or before the 30th calendar day following the end of the subject calendar quarter.	Electronic copies of each EDR will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.65	Opacity reports.	?		This section requires that excess opacity emissions measured by the CEMS be reported to the local APCD (in this case, UDAQ).	Copies of excess opacity reports submitted to UDAQ will be maintained at the plant, in a file suitable for agency inspection for a minimum of 3 years.
40 CFR 75.66	Petitions to the administrator.	?		This section provides the procedures for petitioning the EPA for alternatives to the monitoring requirements of Part 75. IPSC has no current plans to petition for alternative monitoring arrangements.	
40 CFR 75.67	Retired units petitions.		?	This section applies to combustion sources seeking to enter the Opt-in Program and then retired (creating an availability of SO2 allowances for use by other sources). IPSC has no such qualifying units; therefore this rule does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 75.70 through 75.75	Subpart H - NO_x mass emissions provisions.		?	This section, which was added when the federal acid rain program NO_x limitations were revised, clarifies the source obligations for units subject to a state or federal NO_x mass emissions reduction program. However, the IPP plant is not subject to such a state or federal program (other than the federal acid rain NO_x limitations); therefore this rule does not apply. It is presumed that UDAQ permit limits for NO_x mass emissions (e.g., lbs/hour or tpy) do not constitute a "state reduction program".	
40 CFR 76, Nitrogen Oxides					
40 CFR 76.1 – 76.4	Definitions and general information regarding 40 CFR 76.		?	Not an applicable standard or limitation; however, these definitions do apply when evaluating other applicable requirements.	
40 CFR 76.5 – 76.6	NO_x limitations for Group I, Phase I boilers and for Group II boilers.		?	Unit 3 will be considered a Group I Phase II boiler; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 C.F.R. 76.7	The owner or operator of a Group 1, Phase II PC-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler shall not discharge, or allow to be discharged, emissions of NO_x to the atmosphere in excess of the following limits, except as provided in §§ 76.8, 76.10, or 76.11: (1) 0.40 lb/MMBtu of heat input on an annual average basis for tangentially fired boilers. (2) 0.46 lb/ MMBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).	?		IPP may not discharge emissions greater than what is allowed.	CEMS documentation.
40 CFR 76.8	The owner or operator of a Phase II PC-fired utility unit with a Group 1 boiler may elect to have the unit become subject to the applicable emissions limitation for NO_x under § 76.5, starting no later than January 1, 1997.		?	IPP Unit 3 construction missed the 1997 deadline; therefore, this rule does not apply.	
40 CFR 76.9	The designated representative of any source with an affected unit subject to this part shall submit, by the applicable deadline under paragraph (b) of this section, a complete acid rain permit application (or, if the unit is covered by an acid rain permit, a complete permit revision) that includes a complete compliance plan for NO_x emissions covering the unit.	?		IPSC has already obtained a Title IV permit that is included as part of the Title V permit. A modification is being applied for by this NOI to account for the addition of Unit 3.	Permit was received and is retained. This NOI is being submitted to accommodate for the addition of Unit 3.
40 CFR 76.10	The designated representative of an affected unit that is not an early election unit and cannot meet the applicable emission limitation, for Group 1 boilers, either LNB technology or an alternative or, for tangentially fired boilers, separated overfire air, may petition the permitting authority for an alternative emission limitation less stringent than the applicable emission limitation.		?	Unit 3 will be able to meet the applicable emission limitation; therefore, this rule does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 76.11	Details emissions averaging plan.		?	IPP is not eligible for the emissions averaging plan; therefore, this rule does not apply	
40 CFR 76.12	Details Phase I NO_x compliance extension.		?	Unit 3 is a Phase II boiler; therefore, this rule does not apply.	
40 CFR 76.13	Provides calculations for excess emissions of NO_x.	?		If Unit 3 has excess emissions of NO_x, the guidelines detailed in this section must be followed.	If NO_x is ever exceeded, document actions required by this section.
40 CFR 76.14 – 76.15	Details requirements for alternative monitoring equipment and alternative emission limitations.		?	IPP will not have either alternative; therefore, these rules do not apply.	
40 CFR 77, Excess Emissions					
40 CFR 77.01 – 77.06	This part of the acid rain regulations specifies the requirements for addressing excess emissions of SO_2 (exceeding allowances).	?		If IPSC has excess emissions of SO_2 in any calendar year it shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the unit's Allowance Tracking System account in accordance with these rules.	If emissions are ever exceeded, the requirements set forth in these rules will be followed and documentation retained.
40 CFR 78, Appeal Procedures for Acid Rain Program					
40 CFR 78	Guidelines and requirements for acid rain program appeals		?	IPP is not requesting an appeal to the acid rain program; therefore, this rule does not apply.	
40 CFR 79, Registration of Fuels and Fuel Additives					
40 CFR 79	Guidelines and requirements for the registration of fuels and fuel additives.		?	IPP does not produce fuels or fuel additives; therefore, this rule does not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 80, Regulation of Fuels and Fuel Additives					
40 CFR 80	Guidelines and requirements for the production and distribution of fuels and fuel additives.		?	IPP does not produce fuels or fuel additives; therefore, this rule does not apply.	
40 CFR 81, Designation of Areas for Air Quality Planning Purposes					
40 CFR 81	Administrative guidelines and requirements.		?	This rule applies to regulators, and is not an obligation of IPP.	
40 CFR 82, Protection of Stratospheric Ozone					
40 CFR 82	Administrative guidelines and requirements.		?	This rule applies to regulators, and is not an obligation of IPP.	
40 CFR 85, Control of Air Pollution From Mobile Sources					
40 CFR 85	Guidelines and requirements for mobile sources		?	This rule applies to automobile manufacturers, distributors and emissions certifications; therefore, it does not apply to IPP.	
40 CFR 86, Control of Emissions From New and In-Use Highway Vehicles and Engines					
40 CFR 86	Guidelines and requirements for highway vehicles and engines.		?	Guidelines and requirements for highway vehicles and engines.	
40 CFR 87, Control of Air Pollution From Aircraft and Aircraft Engines					
40 CFR 87	Guidelines and requirements for aircraft and engines.		?	IPP does not own or produce aircraft or aircraft engines; therefore, these rules do not apply.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 88, Clean-Fuel Vehicles					
40 CFR 88	Guidelines and requirements for clean fuel vehicles.		?	Guidelines for manufacturers of clean fuel vehicles; therefore, this rule does not apply to IPP.	
40 CFR 89, Control of Emissions From New and In-Use Nonroad Compression-Ignition Engines					
40 CFR 89	Guidelines and requirements for nonroad compression-ignition engines.		?	IPP does not own or operate nonroad compression-ignition engines; therefore, this rule does not apply.	
40 CFR 90, Control of Emissions From Nonroad Spark-Ignition Engines					
40 CFR 90	Guidelines and requirements for nonroad spark-ignition engines.		?	IPP does not own or operate nonroad spark-ignition engines; therefore, this rule does not apply.	
40 CFR 91, Control of Emissions From Marine Spark-Ignition Engines					
40 CFR 91	Guidelines and requirements for marine spark-ignition engines.		?	IPP does not own or operate marine spark-ignition engines; therefore, this rule does not apply.	
40 CFR 92, Control of Air Pollution From Locomotives and Locomotive Engines					
40 CFR 92	Guidelines and requirements for locomotives and locomotive engines.	?		IPP does own/operate a locomotive for the unit coal train operation.	
40 CFR 93, Determining Conformity of Federal Actions to State or Federal Implementation Plans					
40 CFR 93	Guidelines for determining conformity of federal actions to SIP.		?	This rule applies to federal agencies and is not an obligation of IPP.	

Summary of Applicable Requirements - Federal Air Quality Regulations

Applicable Requirement	Summary of Requirement	Applicable to Unit 3		Comments	Methods Used to Demonstrate Compliance[a]
		Yes	No		
40 CFR 94, Control of Air Pollution From Marine Compression-Ignition Engines					
40 CFR 94	Guidelines and requirements for marine compression-ignition engines.		?	IPP does not own or operate marine compression-ignition engines; therefore, this rule does not apply.	
40 CFR 95, Mandatory Patent Licenses					
40 CFR 95	Guidelines and requirements for mandatory patent licenses.		?	IPP is not required to obtain a patent; therefore, this rule does not apply.	
40 CFR 96, NO_x Budget Trading Program for State Implementation Plans					
40 CFR 96	Authorizes states to implement a NO_x trading program		?	IPP is not trading NO_x credits; therefore, this rule does not apply.	
40 CFR 97, Federal NO_x Budget Trading Program					
40 CFR 97	Provisions for the federal NO_x Budget Trading Program		?	IPP is not trading NO_x credits; therefore, this rule does not apply.	

[a]The summary of applicable requirements is intended to provide a summary of the portion of the applicable requirement applying to the generating units. It is not intended to replace a regulatory document. Please see the actual regulations for specific information.

PSD Requirements

The proposed project for the IPP Unit 3 addition based on its proposed emissions (emissions provided in Section II) is classified as a major modification to a major source (UAC R307-101-2. Definitions) and therefore, it is subject to Prevention of Significant Deterioration review under UAC R307-405. Permits: Prevention of Significant Deterioration of Air Quality (PSD) because its emissions are above the PSD major modification triggering levels for all PSD regulated pollutants.

The PSD program defines a major stationary source as:

A. Any one of 28 types of sources with the potential-to-emit 100 tons per year or more of any pollutant regulated in the CAA or

B. Any other type of source with the potential to emit regulated pollutants in amounts equal to or greater than 250 tons per year

The IPP facility belongs to one of the 28 listed source categories (fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input).

The PSD review consists of the following:

1. Modeling analysis

2. Best Available Control Technology (BACT) for all regulated pollutants emitted in significant amounts.

MODELING ANALYSIS REVIEW

The PSD rules require the Applicant to include an air quality impact analysis (AQIA) of the proposed project's impact on federal air quality standards and air quality related values, as part of a complete NOI.

The modeling report was prepared by the Staff of the Technical Analysis Section (TAS) and contains a review of the Applicant's air quality impact analysis (AQIA) including the methodology, data sources, assumptions and modeling results used to determine compliance with State and Federal air quality standards. The AQIA document reviewed and referenced in the report is the "*Notice of Intent – Intermountain Power Project Proposed Unit 3,*" prepared by CH2MHill of Salt Lake City, Utah. It was submitted on behalf of the Applicant and received by the Division on May 14, 2003, and additional documents listed earlier in this document.

MODELING APPLICABLE RULES AND ANALYSES

A. Utah Air Quality Rules

The Utah Division of Air Quality (UDAQ) has determined that the Applicant's NOI is subject to the following rules for conducting an AQIA:

R307-401-2 *Notice of Intent Requirements*

R307-401-6	*Condition for Issuing an Approval Order*
R307-403-3	*Review of Major Sources of Air Quality Impact*
R307-403-5	*Offsets: PM_{10} Non-attainment Areas*
R307-405-6	*PSD Areas – New Sources and Modifications*
R307-406-2	*Visibility – Source Review*
R307-410-2	*Use of Dispersion Models*
R307-410-3	*Modeling of Criteria Pollutant Impacts in Attainment Areas*
R307-410-4	*Documentation of Ambient Air Impacts for Hazardous Air Pollutants (HAPs)*

B. Applicability

The proposed increases in emissions of PM, PM_{10}, NO_x, CO, SO_2, VOC, sulfuric acid mist, fluorides, and eleven HAPs exceed the emission thresholds outlined in R307-406-5, R307-410-3 and R307-410-4. Therefore, an AQIA consistent with the requirements of R307-405-6, R307-406-2, R307-410-2, and R307-410-4 was submitted as part of the Applicant's NOI. R307-410-2 and 3 provides further clarification by assigning the burden for conducting AQIAs, and establishes the U. S. Environmental Protection Agency (US EPA) – Guideline on Air Quality Models as a formal basis for defining the scope of the analysis, as well as the model's construction. The results of the AQIA are required to demonstrate the proposed project's impact on state and federal air quality standards, acceptable levels of impact, and action triggering thresholds referenced or listed in R307-401-6(2), R307-401-6(3), R307-403-3(1), R307-403-5(1)(a), R307-405-4(1), R307-405-6(2), R307-405-6(6), and R307-410-4(1)(d). Annual emissions for each pollutant requiring an AQIA are listed in Table 1.

Table 1: Proposed New Emissions from the Addition of Unit 3

Pollutant	Proposed Unit 3 Total (TPY)
NO_x	2775
SO_2	3963.9
PM_{10} (f+c)	990
CO	5946
VOC	107
Lead	0.79
Arsenic	0.18
Beryllium	0.002
Cadmium	0.03
Chromium	0.28
Cobalt	0.03
Manganese	0.15
Mercury	0.09
Selenium	1.02
Acrolein	0.51
Methyl Hydrazine	0.30

C. Required Analyses

R307-405-6(2)(a)(i)(B) requires the Applicant to perform a pre-construction modeling analysis to determine if the extent of the source's impact is significant enough to warrant an on-site measurement of the ambient background concentration levels, for inclusion in the National Ambient Air Quality Standards (NAAQS) analysis. This analysis is required for all pollutants emitted in a significant quantity (i.e., NO_x, SO_2, PM_{10}, and CO).

R307-401-6(2) requires the Division to determine that the proposed project will comply with NAAQS prior to the issuance of an Approval Order (AO). R307-405(6)(2)(a)(i)(B) requires the Applicant to perform a NAAQS analysis for all pollutants emitted in a significant quantity (i.e., NO_2, SO_2, PM_{10}, and CO). This analysis is to include all emissions at the proposed site under normal operating conditions using maximum anticipated short-term release and annual release rates, the ambient background concentration, and if applicable, any contribution from other nearby sources.

R307-401-6(2) requires the Division to determine that the proposed project will comply with PSD increments prior to the issuance of an AO. Under R307-405(6)(2)(a)(i)(B), the Applicant is required to perform a PSD Class I and II increment consumption analysis for NO_2, SO_2, and PM_{10}. The purpose of this analysis is to quantify any degradation in air quality since the major source baseline dates. The major source baseline dates for this analysis are April 21, 1988, for NO_2 and August 17, 1979, for SO_2 and PM_{10}. This analysis is to include all increment consuming emissions of the three pollutants at the proposed site under normal operating conditions using maximum anticipated short-term and annual release rates. If applicable, contributions since the baseline date associated with growth and other increment consuming sources should also be evaluated.

R307-410-4 requires the Applicant to perform a HAPs analysis for any pollutant emitted above a pollutant specific emission threshold value. This analysis is to include all new emissions of the ten pollutants resulting from the proposed modification under normal operating conditions using maximum anticipated one-hour release rates.

Under R307-405-6(2)(a)(i)(B) and R307-406-2, the Applicant is required to perform a plume blight and regional haze analysis to address impacts from the proposed project on visibility in the Class I areas of concern. A plume blight analysis is required to determine if plumes emanating from the proposed project would be visible inside the Class I area. A regional haze analysis is required to determine if the plumes would reduce the visual range of an observer inside the Class I area. The plume blight analysis is to include all emissions of $NO_{2,}$ SO_4, and PM_{10}. The regional haze analysis is to include all emissions of SO_2, SO_4, $NO_{2,}$ and PM_{10}. Both analyses are to include emissions from the proposed project under normal operating conditions with maximum anticipated 24-hour emission rates.

R307-405-6(2)(a)(i)(D) requires the Applicant to perform a soils and vegetation analysis. The analysis will seek to quantify deposition rates for nitrate and sulfate in the Class I areas. This analysis is to include all emissions of NO_2 and SO_2 at the proposed site under normal operating conditions with maximum anticipated annual emission rates.

R307-403-5 requires the Applicant to perform an analysis to address the proposed source's impact on the Utah County PM_{10} non-attainment boundary. The analysis will seek to quantify the combined impact of PM_{10} and two secondary pollutants, in their gaseous form, in the non-attainment area. This analysis is to include all emissions of SO_2, NO_2, and PM_{10} at the proposed site under normal operating conditions with maximum anticipated 24-hour emission rates.

ON-SITE PRE-CONSTRUCTION MONITORING

A. Meteorological Data

Consistent with the US EPA - Meteorological Monitoring Guidance for Regulatory Modeling Applications, on-site data collection using a 50-meter tower commenced on August 1, 2001, and ran through July 31, 2002. Parameters collected on-site included wind speed and direction (10 and 50 meters), vertical wind speed (10 and 50 meters), temperature (2, 10, and 50 meters), barometric pressure, solar radiation, net radiation, precipitation, and relative humidity.

B. Ambient Pollutant Data

A preliminary analysis was conducted to determine the necessity for pre-construction ambient pollutant monitoring. The modeling results were compared against R307-405-6(6) – *Exemptions - Monitoring Requirements.* The meteorological data set used in the preliminary modeling analysis was derived from worst-case screening meteorological data. The results indicated that SO_2 concentrations exceeded the monitoring trigger level and PM_{10} concentrations approached the trigger level. The Applicant performed one year of on-site SO_2 monitoring to quantify ambient concentrations around the proposed site. As a precaution, the Applicant also performed one year of on-site PM_{10} monitoring at the site. See Section VI(A) of the IPSC NOI for further details.

MODEL SELECTION

The Industrial Source Complex Short Term -Version 3 (ISCST3) is the preferred model specified in the US EPA – Guideline on Air Quality Models to predict air pollutant concentrations in the near field (within 50 kilometers of the source). The US EPA - CALPUFF - Version 5.5 model is the preferred model to predict concentrations in the far field (long range transport conditions beyond 50 kilometers from the source).

MODELING INPUTS AND ASSUMPTIONS

A. Technical Options

The regulatory default options were selected in ISCST3 by the Applicant to quantify all concentrations. The CALPUFF model options and assumptions used in the analysis are discussed in Section 7 of the NOI.

B. Urban or Rural Area Designation

A review of the appropriate 7.5-minute quadrangles determined that the area should be classified as “rural” for air modeling purposes.

C. Topography/Terrain

The Plant is at an elevation of 4687 feet with distant terrain features that have little affect on concentration predictions.

a. Zone: 12
b. Approximate Location: UTM (NAD27): 364213.6 meters East
4374464.2 meters North

D. Ambient Air

It was determined that the Plant boundary used in the AQIA meets the State's definition of an ambient air boundary.

E. Receptor and Terrain Elevations

The near-field modeling domain (78 km x 78 km) used by the Applicant consisted of 10,516 receptors including property boundary receptors. The modeling domain has simple and complex terrain features in the near field. Therefore, receptor points representing actual terrain elevations from the area were used in the analysis.

The far-field modeling domain (524 km x 408 km) consists of a 4-km horizontal grid resolution with eleven vertical layers, and was designed to address the impacts of the proposed project on the five PSD Class I areas in Utah. The terrain elevation data was obtained from the United States Geological Survey's (USGS) Digital Elevation Model (DEM) in NAD 27 format. The terrain data consisted of one-degree quadrangles with a scale of 1:250,000 and a horizontal resolution of 90-meters.

F. Emission Rates and Release Parameters

The emission estimates and source parameters for point and fugitive source at the IPP site and other nearby sources included in the analysis are presented in Sections 3 and 7 and Appendix C and E of the NOI.

G. Building Downwash

The Applicant used the US EPA Building Profile Input Program (BPIP) to determine Good Engineering Practice (GEP) stack heights and cross-sectional building dimensions for input into the ISCST3 model. The output from BPIP showed all stacks to be less than their GEP formula stack height; thereby, requiring a wake effect evaluation.

H. Ambient Background Concentrations

Millard County is in attainment for all pollutants. Background concentrations of NO_2 and CO were obtained from the UDAQ's databases for ambient pollutant monitoring. From the on-site monitoring, the highest recorded 3-hour and 24-hour SO_2 was used to represent the ambient background concentration in the analysis. For the PM_{10} 24-hour ambient background concentration, the second highest recorded value was chosen. Annual ambient background values for SO_2 and PM_{10} represent the average concentration for the monitoring period. The background values used in the NAAQS analysis are presented in Table 2.

Table 2: Background Concentration for the IPP - Unit 3 Power Analysis

Pollutant	Averaging Period	Background Concentration (in µg/m^3)
NO_2	Annual	10.0
SO_2	3-Hour	28.0
SO_2	24-Hour	11.5
SO2	Annual	4.2
PM_{10}	24-Hour	66.0
PM_{10}	Annual	17.7

CO	1-Hour	1150
CO	8-Hour	1150

I. Meteorology Data Processing

For the ISCST3 model, on-site surface data was combined with National Weather Service (NWS) upper air data collected at the Salt Lake City International Airport for the same period using the US EPA – Meteorological Preprocessor for Regulatory Models - Version 99349.

Two meteorological data sets were compiled from the data. The first data set incorporated the wind speed and direction data collected at 10 meters. This data set was used to simulate the dispersion of low-level emissions sources at the site. The second data set incorporated the wind speed and direction data collected at 50 meters. It was used to simulate the dispersion of emissions from the unit-3 217-meter main stack, and other contributing sources having tall stacks capable of long-range transport.

The CALPUFF model uses the CALMET pre-processor to prepare three-dimensional, hourly meteorological fields for CALPUFF. Three-dimensional time-varying fields of meteorological conditions were developed using hourly surface observations obtained from the NWS stations in Salt Lake City, Utah, Cedar City, Utah, Canyonlands National Park, Utah, and Grand Junction, Colorado. The hourly surface observations included: wind speed, wind direction, temperature, cloud cover, ceiling height, surface pressure, relative humidity, and precipitation.

Upper air data required by CALMET included profiles of wind speed, wind direction, temperature, pressure, and elevation. Twice-daily upper air sounding data, obtained from the National Climatic Data Center for Salt Lake City, Utah, Desert Rock, Nevada, Elko, Nevada, and Grand Junction, Colorado, for the period January 1996 through December 1996 were used in the analysis.

One year of MM5 data for the period January 1996 through December 1996, referenced using the UTM coordinate system, was written into the MM5.dat format, and input to the CALMET model.

V. RESULTS AND CONCLUSIONS

The Applicant performed a series of analyses to estimate the impact from the proposed project. Modeling results and conclusions from the review of the analyses are outlined in detail below.

A. Pre-Construction Monitoring Modeling

Prior to the commencement of any on-site monitoring, the Applicant performed a preliminary criteria pollutant analysis of the proposed addition of Unit 3 using ISCST3. This analysis was based on the use of a worst-case meteorological data set. The results of this analysis were used to determine the potential need for on-site ambient pollutant monitoring. Following the collection of one year of on-site meteorological data, the Applicant re-ran the analysis using the on-site meteorology to determine the necessity of any additional ambient pollutant monitoring required by rule. This analysis indicated that potential increases in concentration levels of NO_2, SO_2, and CO were less than the pre-construction monitoring trigger levels listed in R307-405(6)(2)(a)(i)(B). Therefore, no additional pre-construction monitoring was required. The predicted increase in the concentration level of PM_{10} was above the pre-construction monitoring trigger level, supporting the Applicant's decision to perform one year of PM_{10} on-site ambient monitoring. The pre-construction analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Table 3 provides a comparison of the predicted air quality concentrations and monitoring trigger levels.

Table 3: Model Predicted Pre-Construction Monitoring Concentrations

Pollutant/ Averaging Period	Predicted Concentration ($\mu g/m^3$)	Monitoring Trigger Level ($\mu g/m^3$)	Monitoring Required
NO_2 - Annual	0.49	14	No
SO_2 – 24-Hour	6.5	13	No
PM_{10} – 24-Hour	17.3	10	Yes
CO – 8-Hour	21.8	575	No

B. National Ambient Air Quality Standards Analysis

The Applicant performed an ISCST3 modeling analysis to determine if the combined impact from the proposed source, other industrial sources operating in the area, and ambient background would comply with federal NAAQS. The NAAQS analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that the proposed project's predicted 3-hour and 24-hour impacts of SO_2, and 24-hour and annual impacts of PM_{10}, when combined with other industrial sources and ambient background, would comply with federal standards. For 1-hour and 8-hour CO and annual NO_2 and SO_2, the Applicant's analysis indicated that predicted impact from the addition of Unit 3 was insignificant to warrant a cumulative effects analysis. Additional analysis for these pollutants and averaging period conducted in-house indicated that the combined impacts of Units 1, 2, 3, and ambient background would comply with federal standards. Table 4 provides a comparison of the Applicant's predicted air quality concentrations and the NAAQS.

Table 4: Model Predicted NAAQS Concentrations

Pollutant/ Averaging Period	Model Predicted Conc. ($\mu g/m^3$)	Back-ground Conc. ($\mu g/m^3$)	Total Predicted Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2 – Annual	0.49*	NA	NA	100
SO_2 – 3-Hour	192.4	28.0	220.4	1300
SO_2 – 24-Hour	41.1	11.5	52.6	365
SO_2 – Annual	0.73*	NA	NA	80
PM_{10} – 24-Hour	28.5	66	94.5	150
PM_{10} – Annual	5.5	17.7	22.7	50
CO –1-Hour	84.0*	NA	NA	40,000
CO – 8-Hour	21.8*	NA	NA	10,000

* Impacts from the addition of Unit 3 only

C. PSD Class I Increment Consumption Analysis

The Applicant performed a CALPUFF cumulative increment modeling analysis to determine if the impact from the proposed source along with other major increment consuming sources in southern Utah would comply with federal PSD Class I increments. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Table 5 below provides a comparison of the maximum predicted air quality concentrations at the five Class I areas included in the analysis with the increments. Detailed model predicted impacts for each of the five Utah Class I areas are outlined in Table 7-5 of the NOI.

Table 5: Model Predicted PSD Class I Increment Concentrations

Pollutant/ Averaging Period	Predicted Concentration (μg/m^3)	PSD Class I Increment (μg/m^3)
NO_2 – Annual	0.11	2.5
SO_2 – 3-Hour	8.39	25
SO_2 – 24-Hour	2.10	5
SO_2 – Annual	0.13	2
PM_{10} – 24-Hour	0.20	8
PM_{10} – Annual	0.02	4

D. PSD Class II Increments

The Applicant performed an ISCST3 modeling analysis to determine if the combined impact from the proposed source and other increment consuming sources operating in the area would comply with PSD Class II increments. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that the proposed project's predicted 3-hour and 24-hour impacts of SO_2, and 24-hour and annual impacts of PM_{10}, when combined with other increment consuming sources in the area, would comply with federal standards. For annual NO_2 and SO_2, the Applicant's analysis indicated that predicted impact from the addition of Unit 3 was insignificant to warrant a cumulative effects analysis. Table 6 provides a comparison of the predicted concentrations and the PSD Class II increments. The increment analysis indicated that the amount of PM_{10} 24-hour increment consumed by the proposed project would be greater than 50% of the standard; therefore, approval under R307-401-6(3) from the Utah Air Quality Board would be required.

Table 6: Model Predicted PSD Class II Increment Concentrations

Pollutant/Averaging Period	Predicted Concentration (μg/m^3)	PSD Class II Increment (μg/m^3)
NO_2 – Annual	0.49*	25
SO_2 – 3-Hour	192.4	512
SO_2 – 24-Hour	41.1	91
SO_2 – Annual	0.73*	20
PM_{10} – 24-Hour	28.5	30
PM_{10} – Annual	5.5	17

* Impacts from the addition of Unit 3 only

E. Hazardous Air Pollutants

The Applicant performed an ISCST3 modeling analysis to determine the impact from HAPs released by the proposed source on the surrounding area. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. The analysis indicated that predicted concentrations of HAPs from the proposed project would be less than the UDAQ-Toxic Screening Levels (TSLs), and no further documentation of impacts would be required. Table 7 provides a comparison of the predicted HAP concentrations and UDAQ-TSLs.

Table 7: Model Predicted Hazardous Air Pollutant Concentrations

Pollutant/Averaging Period	Predicted Concentration ($\mu g/m^3$)	UDAQ –TSL ($\mu g/m^3$)
Arsenic – 24 Hour	3.02E-04	3.3E-01
Beryllium – 24 Hour	3.14E-06	7.0E-02
Cadmium – 24 Hour	5.36E-05	2.0E-02
Chromium – 24 Hour	4.49E-05	1.1E-01
Cobalt – 24 Hour	5.36E-05	7.0E-01
Manganese – 24 Hour	2.45E-04	6.7
Mercury – 24 Hour	1.02E-04	3.3E-01
Selenium – 24 Hour	1.39E-03	6.7
Acrolein – 24 Hour	7.02E-04	7.7
Methyl Hydrazine – 24 Hour	4.12E-04	6.0E-01

F. Visibility – Plume Blight

The Applicant performed a VISCREEN - Level 1 and 2 analyses to determine if plumes emanating from the proposed project would be visible from the five Class I areas. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the analysis indicate that plume visibility from the proposed project is within acceptable limits inside the five Class I areas.

G. Visibility – Regional Haze

The Applicant performed a CALPUFF modeling analysis, consistent with the recommendations outlined in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report, to determine if emissions from the proposed project would result in a notable reduction to background visual range within the five Class I areas. Results from the CALPUFF modeling analysis were processed using the CALPOST post-processing module to calculate the change in background extinction (b_{ext}). In doing so, the Applicant used Method 2, which calculates relative humidity factors (f(RH)) from the hour-by-hour RH found in the master surface data file that CALMET produces. Results of this analysis indicated that the predicted change in b_{ext} would be less than the 5% threshold that is used to determine if a cumulative analysis is required, in Arches and Zion National Parks. Visibility impacts in Bryce Canyon, Canyonlands and Capital Reef National Parks exceeded the 5% threshold.

FLAG guidance allows for further refinement of the b_{ext} value by incorporating hourly transmissometer data measured at in or near the Class I areas of concern. The analysis refinement was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the refined haze analysis indicated that the predicted changes in b_{ext} in the five national parks would be less than the 5% threshold provided in FLAG; and therefore, no further analysis was required. Table 8 provides a comparison of the maximum predicted change in background extinction for the Class I areas included in the analysis and the FLAG b_{ext} threshold used to determine if a cumulative analysis is required.

Table 8: Model Predicted Regional Haze Impacts

National Park/ Wilderness Area	Predicted b_{ext} (%)	Cumulative Analysis Threshold (%)
Canyonlands National Park	4.43*	5
Zion National Park	4.14	
Arches National Park	2.83	
Bryce Canyon National Park	4.92*	
Capitol Reef National Park	3.02*	

* b_{ext} values based on hourly transmissometer data

H. Soils and Vegetation Analysis

The Applicant performed an analysis to determine the extent of impacts from the proposed source on soil and vegetation in the Class I areas. Along with a discussion of soils and vegetation, the Applicant performed an analysis to predict deposition rates of sulfur and nitrogen in these areas. The CALPUFF model was used to predict wet and dry fluxes of SO_2, SO_4, HNO_3, and NO_3. The CALPOST post-processing module was then used to adjust for molecular weight, sum the total fluxes, and develop an average flux rate and annual deposition rate. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Deposition rates were compared against the Deposition Analysis Threshold (DAT) recommended in the FLAG Report. Deposition rates were predicted to be less than the DAT in all Class I areas except for sulfate deposition in Capital Reef National Park. Results of the analysis are listed in Table 9.

Table 9: Model Predicted Nitrate and Sulfate Deposition Rates

National Park/ Wilderness Area	Total Nitrate Deposition Rate (kg/ha/yr)	Total Sulfate Deposition Rate (kg/ha/yr)	Deposition Analysis Threshold (kg/ha/yr)
Canyonlands National Park	0.002	0.004	0.005
Zion National Park	0.001	0.004	
Arches National Park	0.002	0.003	
Bryce Canyon National Park	0.001	0.004	
Capitol Reef National Park	0.002	0.006*	

* Exceeds FLAG Guidance DAT

I. Non-attainment Boundary Impact Analysis

The Applicant performed an analysis to determine if the combined impact of NO_2, SO_2, and PM_{10} from the proposed source would exceed the threshold trigger levels outlined in R307-403-5, in the Utah County non-attainment area. Results from the CALPUFF analysis were processed using the CALPOST post-processing module to combine the predicted concentrations of the three pollutants. The analysis was reviewed by the Division and determined to be consistent with the requirements of R307-410-2. Results of the analysis indicated that the predicted impact on the non-attainment area would be below the threshold levels; and therefore, would not require emission offsets. Results of the analysis are listed in the Table 10.

Table 10: Model Predicted Utah County Non-Attainment Boundary Impacts

Pollutant/ Averaging Period	Predicted Concentration in The Utah County Non-attainment Area (µg/m^3)	Threshold Trigger Level to Require Offsets (µg/m^3)
Total – 24 Hour	1.94	3
Total – Annual	0.15	1

IV.   BEST AVAILBLABLE CONTROL TECHNOLGY (BACT) ANALYSIS

State and federal regulatory programs require the implementation of emissions controls for the proposed project. Utah requires a BACT analysis and determination be performed for each individual new emissions unit and pollutant emitting activity at which a net emissions increase would likely occur. Individual BACT analysis and determinations are performed for each pollutant subject to a PSD review.

IV.1 Applicability of BACT Requirements

A new facility in Utah, by law, must consider the best control of all the emissions. Control may be achieved by a) good process design, b) sound operating practices, c) best emission control devices available, or d) a combination of these controls. Utah Air Conservation Rule R307-401-6 indicates that an approval order will be granted if the following conditions have been met:

The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology except as otherwise provided in Title R307.

As the rule states, BACT must be based on the most effective engineering techniques and control equipment necessary to minimize emissions of air contaminant to the outside environment from its process.

IV.1.1 Pollutants Subject to BACT

Based on emissions increases resulting from the addition of Unit 3, this project is considered a major PSD modification of an existing major stationary source and it must conduct PSD BACT for SO_2, NO_x, CO, VOCs (including organic HAPs), PM, PM_{10} (including trace metal HAPs), lead, H_2SO_4, fluorides, TRS, and RSCs. BACT determinations are made on case-by-case basis that involves an assessment of the applicability of available technologies capable to sufficiently reduce specific pollutant emissions in economical way considering energy, and environmental impacts for each technology. Also, BACT analysis and determination will be performed for each individual new emissions unit and pollutant emitting activity at which a net emissions increase would likely occur.

IV.2 BACT ANALYSIS METHOD and BASIS

Supporting Information for the BACT analysis performed that is not included in this engineering review can be found in the IPA NOI dated May 14, 2003, and it is follows;

- Appendix C: Detailed Emissions Calculations
- Appendix F: Tables with Control Technologies and Emissions Rates for the Coal Fired Boilers from the NSR RACT/BACT/LAER Clearinghouse Database,
-
- Appendix H: Summary of Various Technologies Available Review Summary for SO_2, TRS, RSCs, H_2SO_4, NO_x, CO, VOC, PM, PM_{10}, Lead, and Fluoride with brief technology description and applicability of each technology to coal-fired boilers.

- Appendix G: Cost Estimates for Selective Catalytic Reduction and Wet Limestone FGD

- Different control technologies descriptions can be found in the Process Description Section 2.0 and BACT Section 6.0.
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Appendix I: Technological Discussions for:

-Coal Supply*,
-Nitrogen Emissions and Controls,
-Evaluation of Wet Electrostatic Precipitators to Control Sulfuric Acid Mist Emissions*,
-Sulfur Dioxide Control-Flue Gas Desulfurization and Control Efficiency*
-Effect of Averaging Time on Wet FGD System Performance and Design*
* part of the NOI submitted May 14, 2003

PM_{10} BACT
-IPP Unit 3—PM_{10} BACT Cost Estimate, November 7, 2003
-IPP Unit 3—PM_{10} BACT Questions, November 7, 2003
-IPP Unit 3—PM_{10} BACT Questions, December 18, 2003)
-PM_{10} BACT Cost Analysis, January 12, 2004)

SO_2 BACT
-Wet Flue Gas Desulfurization Control Efficiency, November 18, 2003

CO/VOC BACT
-IPP Unit 3 Air Permit Application: Review of CO and VOC Permit Limits (revised), March 29, 2004
Response to UDAQ BACT Questions
-Intermountain Power Project Unit 3 Permit Application: Response to UDAQ Questions, July 28, 2003
Mercury MACT
- -IPP Unit 3 Air Permit Application: Review of Mercury Permit Conditions (revised), September 8, 2003

Review of PC, IGCC and CFB BACT technology, dated November 26, 2003 for BACT

A methodology used in this study to determine BACT follows the "top-down" approach. The "top-down" BACT analysis contains the following elements:

- ?? A determination of the most stringent control alternatives potentially available.
- ?? An assessment of the technical and economic feasibility of each alternative.
- ?? An assessment of beneficial and adverse energy impacts, environmental impacts, and economic impacts, of technically feasible alternatives.
- ?? Selection of the best technically feasible control alternative, considering the beneficial and adverse impacts of each.
- ?? Confirmation that the selected BACT is at least as stringent as applicable NSPS and SIP limits for the source.

EPA guidance recommends that the BACT analysis be conducted using 5 basic steps. These steps are applied sequentially for each emission unit and each pollutant as discussed below:

Step 1. Identify All Available Control Technologies. This is a compilation of all control technologies available and having the potential to reduce emissions of the pollutant in question. The list does not exclude technologies implemented outside the United States. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and are included as control alternatives.

Step 2. Eliminate Technically Infeasible Options. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. This demonstration, and the evaluation of what constitutes an "identical or similar" process, is based on physical, chemical, and engineering principles.

Step 3. Rank Remaining Control Technologies by Control Effectiveness. The remaining control alternatives not eliminated in Step 2 are ranked in order of most effective (i.e. lowest emission rate) to the least effective.

Step 4. Evaluate Most Effective Controls and Document Results. The information developed in Step 3 is objectively evaluated to determine whether economic, environmental, and energy impacts are sufficient to justify exclusion of the technology. The analysis begins with the top ranked technology and continues until the technology under consideration cannot be eliminated by any economic, environmental, and energy impacts, which justify that, the alternative is inappropriate as BACT.

Step 5. Select BACT. The most effective control option not eliminated in Step 4 is identified as BACT.

Each of these steps has been conducted for SO_2, TRS, RSCs, H_2SO_4, NO_x, CO, VOC, PM, PM_{10}, lead, and fluorides and is described below. Emissions of mercury are less than the PSD significance level of 0.1 tpy.

BACT Analysis for Unit 3 Boiler SO_2 Emissions

The BACT analysis for SO_2 presented below is also applicable to the related compounds (TRS, RSCs) and inorganic HAPs.

The generation of sulfur dioxide (SO_2) in a coal-fired utility boiler is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal.

IPP has proposed firing the new Unit 3 primarily on Utah bituminous coal. Based on historical analyses of Utah bituminous coal, IPP has projected that the worst-case design fuel (e.g., the fuel that will result in the highest emission rates) will have a heating value of 11,193 Btu/lb, and maximum sulfur content of 0.75% by weight. Assuming 100% of the fuel sulfur converts to SO_2 in the boiler, the maximum SO_2 emission rate, without post-combustion controls, would be 1.34 lb/MMBtu. An emission rate of 1.34 lb/MMBtu is equivalent to an SO_2 concentration in the flue gas of approximately 686 ppmvd @ 3% O_2.

Step 1

The potential $SO_{2,}$ emission reduction options identified and applicable to coal-fired boilers include pre-combustion controls and post-combustion controls. Potential SO_2 control strategies are discussed below:

Pre-combustion controls:

- Fuel Switching

A potential control for reducing SO_2 emissions from the proposed project is reducing the amount of sulfur content in the coal.

Comparison of Utah to PRB Coals

Both Utah coals and PRB coals are considered low sulfur coals in that a large majority have a sulfur content less than 0.7 % by weight, although a few mines produce coal with a sulfur content above 1.0%. The larger difference between Utah coals and PRB coals is that PRB coals are mostly sub-bituminous by coal ranking (i.e., PRB coal heat contents range from 8,400 to 8,800 Btu/lb, as received basis), compared to Utah coals, which are bituminous (i.e., Utah coal heat contents range from 11,100 to 13,100 Btu/lb, as received basis). The higher heat content of Utah coals has a significant effect on post-combustion SO_2 concentration. Therefore, the post-combustion SO_2 concentration for a typical Utah coal is comparable to a typical PRB fuel, as shown in Table 1 below:

Table 1
Comparison of Sulfur Content in Coal vs. Design Basis

	Utah Typical	PRB Typical	Unit 3 Design Basis	Typical PRB Design Basis	Design Basis Used at Wygen 2[1]
Higher heating Value (Btu/lb)	11,800	8,800	11,193	8,000	7,950
Sulfur by weight (%)	0.6	0.4	0.75	0.51	1.0
Uncontrolled SO_2 rate into Wet-FGD system (lb/mmBtu)	1.02	0.91	1.34	1.275	2.52
Percent difference	12.1% above typical PRB	Base	5.1% above design PRB	Base	87.7% higher than IPA Unit 3 Design Basis

[1] Wygen Unit 2,Wyoming, Pulverized Coal 500 MW, Dry Lime FGD

A comparison of PRB coal with Utah coal must include a comparison of the design range that must be allowed for permitting and designing of a coal-fired plant. The uncontrolled SO_2 emission rates to the FGD control system will be essentially the same; therefore, overall economics of the coal must be taken into consideration. On an economic basis, a typical Utah coal can be delivered to IPP Units 1&2 for approximately $0.39/MMBtu less than a typical PRB coal. If assumed, for comparison purposes, Utah coal with a sulfur content of 0.6 % (approximately equal to IPSC's current coal supply) and a Unit 3 scrubber efficiency of 92.6% compared to the PRB coal at 0.4% sulfur and a Unit 3 scrubber efficiency of 92.6%, the cost/ton of SO_2 reduction using a typical PRB coal instead of a Utah coal would be approximately $148,000/ton (Table 2).

Table 2
PRB Coal Cost Effectiveness Compared to Utah Coal Due to Lower Sulfur

Scrubber Efficiency	Total Annual Cost ($/year)	Annual Emission Reduction, (tpy)	Ave Annual Cost Effectiveness, ($/ton)
92.6 %	$47,800,000	323	$148,000

Conclusion:

- Requiring IPSC to use PRB fuel exclusively would represent a prohibitive, adverse economic impact particularly in light of the small incremental decrease is SO_2 emissions achieved by the PRB coal. - The uncontrolled SO_2 emission rate would not be significantly improved by using PRB coal over Utah coal.
- The controlled SO_2 emission rate would be essentially identical with either PRB or Utah coal.
- Adverse environmental and energy impacts due to transportation of coal from out-of-state mines would at least partially outweigh any beneficial environmental impacts due to reduced SO_2 emissions.
- Based on consideration of all beneficial and adverse energy, economic, and environmental impacts,

UDAQ has concluded that coal switching does not represent BACT for SO_2 emissions from IPP Unit 3.

Post-combustion controls

- Wet limestone scrubbing
- Wet lime scrubbing
- Lime spray dryer
- Circulating dry scrubber

Step 2

The first three of the post combustion controls options are technically feasible for use in reducing SO_2 emissions from IPP Unit 3. However, the use of a circulating dry scrubber requires the use of high calcium fly ash to provide the alkalinity needed to react with SO_2. The potential coals for IPP Unit 3 are not particularly high in calcium. In addition, control efficiencies for circulating dry scrubbers have not been demonstrated to be above 80 percent in the RBLC database. For these two reasons this technology was eliminated from further consideration.

Step 3

Emission rates for each of the remaining SO_2 removal technologies are ranked in order of their control effectiveness. These effectiveness values are provided in the table below.

SO_2 Control Technology Emission Rate Ranking

Control Technology	SO_2 Outlet Concentrations (lb/MMBtu) [a]
Wet Limestone Scrubbing	0.10 – 0.40
Wet Lime Scrubbing	0.13 – 0.25
Lime Spray Dryer	0.10 – 0.32
NSPS Limit	0.40 [a]

[a] Based on an uncontrolled SO_2 emission rate of 1.34 lb/MMBtu and a removal efficiency of 70 percent, which is the applicable standard under NSPS subpart Da when SO_2 emissions are less than 0.60 pounds per MMBtu

Step 4

Wet Limestone Scrubbing Systems, especially those employing forced oxidation, have become state-of-the-art for achieving SO_2 removal from coal-fired boiler flue gas. The wet limestone scrubbing process uses alkaline slurry made by adding limestone ($CaCO_3$) to water. The alkaline slurry is sprayed in the absorber, typically countercurrent to the flue gas flow, and reacts with SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) solids are formed in the scrubber and are removed as a wet solid waste by-product.

Since wet limestone scrubbing represents the most effective SO_2 control technique that can be applied to PC-fired boilers, and considering the presented control technology emission rate ranking, an economic evaluation is not required. The use of wet limestone scrubbing for SO_2 control results in the production of a large quantity of by-product that must be disposed of in an environmentally responsible manner. The by-product will be blended with fly ash for landfill disposal on the IPP site. The energy, environmental, and economic impacts associated with wet limestone scrubbing are similar to the wet lime and spray dry systems. The use of a wet FGD system (limestone or lime) can also result in increased condensable PM_{10} emissions. Condensable PM_{10} includes emissions of HCl, HF, H_2SO_4, and $(NH_4)_2\ SO_4$.

Step 5

The final step in the top-down BACT analysis process is to select BACT. EPA's RBLC database and other recently issued permits were again consulted to assist in selecting BACT for this project.

The SO_2 BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in the table below:

Comparison of PC Boiler SO_2 Emission Rates

Recently Issued PSD Permits – SO_2 Limits

Name	Type/Size	SO_2 Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.12 lb/MMBtu (30 day rolling avg) 0.13 lb/MMBtu (3 hour avg)	Lime Spray Dryer
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	Voluntary limit: 8,448 lb/hr Units 1-4 (3 hour rolling avg) 10,800 tpy Units 1-4	Lime Spray Dryer Netted with Units 1 and 2 – no increase in facility SO_2 emissions
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.12 lb/MMBtu (30 day rolling avg)	Lime Spray Dryer
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.167 lb/MMBtu (30 day rolling avg) 0.41 lb/MMBtu (24 hour avg)	Wet Limestone FGD
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.10 lb/MMBtu (30 day rolling avg) 0.15 lb/MMBtu (3 hour block avg)	Lime Spray Dryer
Bull Mountain Roundup Units 1 and 2 Montana	Pulverized Coal 390 MW each	0.12 lb/MMBtu (24 hour avg) 0.15 lb/MMBtu (1 hour avg) 0.12 lb/MMBtu (30-day rolling avg)	Lime Spray Dryer
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.16 lb/MMBtu (3 hour rolling avg) (24 hour rolling avg (30 day rolling avg)	Lime Spray Dryer
Rocky Mountain Power, Hardin Unit	Pulverized Coal 113 MW	0.15 lb/MMBtu (30 day rolling avg)	Wet Lime FGD

Name	Type/Size	SO_2 Limit	Control Equipment
1 Montana		(3-hr and 24-hr rolling avg)	
Prairie State Units 1 and 2, Illinois	Pulverized Coal 750 MW each	0.182 lb/MMBtu (30-day rolling avg)	Wet Limestone FGD
Council Bluffs Energy Center Unit 4, Iowa	Pulverized Coal 750 MW	0.10 lb/MMBtu (30-day rolling avg)	Lime Spray Dryer
Cross Units 3 and 4, South Carolina	Pulverized Coal 600 MW each	0.13 lb/MMBtu (365-day rolling avg)	Wet Limestone FGD
Longview Energy Center, West Virginia	Pulverized Coal 600 MW	0.12 lb/MMBtu (24-hr avg)	Wet Limestone FGD
Elm Road Generating Station, Units 1 and 2 Wisconsin	Pulverized Coal 600 MW (6,180 MMBtu/hr)	0.15 lb/MMBtu (30-day rolling avg) 1,150 lb/hr SO_2 3-hr rolling avg, 1,050 SO_2 24- rolling avg	Wet Limestone FGD

All the permits above exempt startup, shutdown, and malfunction except Bull-Mountain Roundup Unit 1, Montana and Elm Road Generating Station, in the short-term (1 hour, 3 hour, 24 hour, and 30 day) emission limits.

Both wet lime scrubbing and wet limestone scrubbing have been demonstrated at removal efficiencies of 95 percent or greater when firing high-sulfur coal. The installation of a wet limestone scrubber on IPP Unit 3 will result in an SO_2 removal efficiency more than 90% efficiency.

Achieving a controlled emission rate of 0.10 lb/MMBtu will require a control efficiency of about 92 % when firing the worst-case design fuel. The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium controlled reactions occurring in the gas, liquid, and solid phases. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent liquid. If no soluble alkaline species are present in the liquid, the liquid quickly becomes saturated with SO_2 and absorption is limited.

Likewise, as the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure. Therefore, high control efficiencies are easier to achieve as the flue gas SO_2 concentration increases, and high control efficiencies would not be expected as the flue gas SO_2 concentration is reduced. Because control efficiency is a function of the SO_2 concentration in the flue gas, control efficiency can be a misleading indicator of the effectiveness of a FGD system. The SO_2 concentration in the boiler flue gas is a function of the fuel's heating value and sulfur content. Depending on the fuel characteristics, uncontrolled SO_2 concentrations in utility boiler flue gas typically range from approximately 1,200 to 4,500 ppmvd. The Utah bituminous fuel proposed for Unit 3 has a relatively high heating value and relatively low sulfur content, and the maximum uncontrolled SO_2 concentration in Unit 3 is expected to be around 686 ppmvd. Based on a review of recently submitted PSD permit applications for pulverized coal fired boilers, the most aggressive proposed SO_2 control efficiencies are associated with boilers that will burn high sulfur coals and have a high uncontrolled SO_2 concentration in the boiler flue gas. For example, the Thoroughbred Generating Station proposed wet FGD with an SO_2 control efficiency of 97.9% (based on worst-case design fuel). Likewise, the Prairie State Generating Station proposed wet FGD with a control efficiency of 97.9%. However, both of these projects will utilize a high-sulfur midwestern bituminous coal.

A comparison of the fuel characteristics, flue gas SO_2 concentration, control efficiencies, and proposed controlled SO_2 emission rates for Thoroughbred, Prairie States, and IPP Unit 3 is provided below:

	Worst-Case Design Fuel Characteristics		Maximum Uncontrolled SO2 Emission Rate	Approximate Uncontrolled SO2 Concentration in Flue Gas	Proposed Control Efficiency	Approximate Controlled SO2 Concentration
	Heating Value	Sulfur Content				
Facility	(Btu/lb)	(%)	(lb/mmBtu)	(ppmvd)	(%)	(ppmvd)
Thoroughbred	9,962	4.24	8.51	4,358	97.9	91.5
Prairie State	8,780	4.0	9.11	4,665	97.9	98.0
Intermountain	11,193	0.75	1.34	686	92.5	51.5

As discussed, control efficiency is a function of several variables, including the concentration of SO_2 in the flue gas. The fuel proposed for IPP Unit 3 will generate only approximately 15% of the flue gas SO_2 generated by firing a higher sulfur bituminous coal. Although physical/chemical constraints of the wet FGD system may limit the control efficiency at IPP, IPP's controlled SO_2 emission rate will still be significantly lower than the emission rate achieved at similar projects.

To conclude the efficiency comparison, control efficiency is a function of the uncontrolled SO_2 concentration in the flue gas. High control efficiencies cannot be maintained as the uncontrolled flue gas SO_2 concentration decreases. Therefore, control efficiency can be a misleading indicator of a control system's effectiveness.

The design SO_2 emission rate on IPP Unit 3 is proposed at 0.10 lb/MMBtu (30-day rolling average) which is as low as any of the applicable units in the RBLC database including the recently issued PSD permits summarized in the table above. An emission rate of 0.10 lb/MMBtu represents the most stringent SO_2 emission rate permitted at any similar source, and will require a control efficiency about 92% base on worst-case design fuel. IPP's SO_2 emission rate will be significantly lower than the emission rate achieved at similar projects.

Based on information provided in the IPSC Unit 3 NOI, IPSC SO_2 BACT supporting documents for BACT, existing Units 1 and 2 WFGD performance, and Acid Rain database, for IPP Unit 3, BACT for SO_2 is determined to be 0.10 (30-day rolling average) excluding startup, shutdown and malfunction (SSM) periods.

The BACT analysis for H_2SO_4

H_2SO_4 Analysis

Sulfuric acid mist (H_2SO_4) is generated in a coal-fired boiler when sulfur trioxide (SO_3) in the flue gas reacts with water to form sulfuric acid. A small portion of the sulfur dioxide (SO_2) generated in the boiler will oxidize to SO_3 during the combustion process, and some additional SO_2 to SO_3 oxidation will occur across the SCR. Based on operating information from existing coal-fired boilers, and information available from equipment vendors, it is estimated that approximately 1.0% of the flue gas SO_2 will oxidize to SO_3 in the boiler, and that an additional 1.2% of the flue gas SO_2 will convert to SO_3 across the SCR. SO_3 is hygroscopic and will absorb moisture to form H_2SO_4 at gas temperatures below the sulfuric acid dew point.

A portion of the SO_3 generated in the boiler and SCR will be captured in the unit's flue gas desulfurization system. IPA proposed wet FGD as BACT for SO_2 because it will provide the most stringent SO_2 control. SO_3, which is very reactive, will react with alkaline components of the desulfurization scrubber slurry. However, in the case of wet FGD, SO_3 entering the wet scrubbers may also react with water and create micron sized sulfuric acid droplets. Some of the micron-sized droplets may pass through the FGD spray levels and the mist eliminator, and be emitted as sulfuric acid mist.

SO_3 generated in the boiler and SCR may also be captured in the unit's fabric filter (BACT for PM_{10} control). Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which the flue gas must pass. SO_3 will readily react with alkaline components of the fly ash at temperatures below the H_2SO_4 dew point to form sulfate salts. The SO_3 removal efficiency of a fabric filter is dependent upon the alkalinity of the fly ash cake. Fabric filters associated with highly alkaline fly ash may significantly reduce the SO_3 concentration in the flue gas.

In its BACT analysis IPSC concluded, based on the design coal information, and information available in the technical literature, that the wet FGD system would reduce potential H_2SO_4 emissions by approximately 40% (Intermountain Power Project, Notice of Intent, December 2002, page 6-1). No additional credit was taken for H_2SO_4 removal in the unit's fabric filters. To more accurately characterize the site-specific SO_3 generation rates and removal efficiencies in a boiler similar in design to the proposed Unit 3, IPA conducted stack testing at the existing IPP Unit.

Based on the results of the stack tests, and information available in the technical literature, the following SO_3/H_2SO_4 generation rates and control efficiencies will be used in this evaluation:

SO_2 to SO_3 Conversion in the Boiler 1.0%
SO_2 to SO_3 Conversion in the SCR 1.2%
SO_3 removal in the Fabric Filter 40%
H_2SO_4 Removal in the Wet FGD 84%
Overall H_2SO_4 Removal Efficiency 90%

Based on a worst-case design fuel (i.e., fuel that results in the highest SO_2/SO_3 emission rate), the maximum potential H_2SO_4 emission rate is calculated to be 0.045 lb/MMBtu. Assuming the control efficiencies listed above, the system will achieve an overall H_2SO_4 control efficiency of approximately 90% with the fabric filter and wet FGD. Based on an overall control efficiency of 90%, the controlled H_2SO_4 emission rate will be reduced to 0.0044 lb/MMBtu (or approximately 1.5 ppmvd @ 3% O_2). Emission calculations are provided in Tables 1 and 2.

Table 1
Calculation of Maximum Uncontrolled Sulfuric Acid Mist Emissions

Parameter	Unit	Value
Full Load Heat Input to Boiler	mmBtu/hr	9,050
Primary Fuel Feed Rate	lb/hr	808,541
Sulfur Content	%	0.75
Potential SO_2 in Boiler Flue Gas	lb/hr	12,128
Potential SO_2 in Boiler Flue Gas	lbmole/hr	189.5
SO_2 to SO_3 Conversion in Boiler	%	1%
Potential SO_3 in Boiler Flue Gas	lbmole/hr	1.9
SO_2 Entering the SCR	lbmole/hr	187.6
SO_2 to SO_3 Conversion in SCR (estimate)	%	1.2%
SO_3 Generated Across SCR	lbmole/hr	2.27
Potential Flue Gas SO_3 (Exiting the SCR)	lbmole/hr	4.17
SO_3 to H_2SO_4 Conversion	%	100
Potential H_2SO_4 Emissions	lb/hr	408
Potential H_2SO_4 Emission Rate	lb/mmBtu	0.045

Table 2
Calculation of Sulfuric Acid Mist Emission Controls

Parameter	Unit	Value
SO_3 Entering the Fabric Filter	lb/hr	333
SO_3 Removal in the Fabric Filter	%	40
SO_3 Entering the FGD	lb/hr	200
Potential H_2SO_4 in the FGD	lb/hr	245
H_2SO_4 Removal in the FGD	%	84%
Controlled H_2SO_4 Emissions	lb/hr	40
Controlled H_2SO_4 Emission Rate	lb/mmBtu	0.0044
H_2SO_4 Concentration in Stack Gas	ppmvd @ 3% O_2	1.5

Step 1

H_2SO_4, and the precursor to H_2SO_4 (SO_3) will be captured in emission control technologies designed to control SO_2. Therefore, the same potential control technologies evaluated for SO_3 control were also evaluated for H_2SO_4 control. In addition, SO_3 generated in the boiler and SCR may be captured in the unit's fabric filter, therefore fabric filtration was included in the control technology evaluation. One additional post-FGD control technology, wet electrostatic precipitation (WESP), was also identified as a potential H_2SO_4control technology. H_2SO_4 control technologies evaluated included:

- Wet limestone scrubbing
- Wet lime scrubbing
- Lime spray dryer
- Circulating dry scrubber
- Fabric filter
- Wet electrostatic precipitation

Step 2

All of the control options listed above are technically feasible for use in reducing H_2SO_4 emissions.

The use of a circulating dry scrubber generally requires the use of high calcium fly ash to provide the alkalinity needed to react with SO_3. The potential coals for IPP Unit 3 boiler are not particularly high in calcium. Furthermore, because of the high particulate loading associated with a circulating dry scrubbing system, the pressure drop across a fabric filter is generally unacceptable, and dry electrostatic precipitators are generally used for particulate control. Based on this it can be concluded that a fabric filter represents BACT for particulate matter control, and therefore, will not consider dry electrostatic precipitation for particulate matter control. Finally, the circulating dry scrubber has limited application, and has not been used on large pulverized coal-fired boilers. Assuming that a circulating dry scrubber system could be designed for the proposed project, it is anticipated that the SO_2 and SO_3 control efficiencies would be lower than the control efficiency of the proposed control system. For these reasons, circulating dry scrubbing was eliminated from further consideration.

In addition, BACT for H_2SO_4 control technology needs to be compatible with the control technology defined as BACT for SO_2 and PM_{10}. In the BACT section for the PM_{10} it was determined that a fabric filter represents BACT for the control of PM_{10}, and in the BACT section for SO_2 it was determined that wet limestone scrubbing represents BACT for the control of SO_2. Therefore, based on site-and coal specific considerations, circulating dry scrubbing, wet lime scrubbing, and lime spray drying must be excluded from further consideration and only control technologies that can be used in conjunction with a fabric filter and wet limestone scrubbing will be considered technology feasible for the control of H_2SO_4.

With respect to wet electrostatic precipitation (WESP), there is limited commercial operating experience upon which to base a conclusion regarding the technical feasibility and effectiveness of WESP on a large utility boiler fired on Utah bituminous coal. The proposed Unit 3 is a nominal 950-gross MW unit, which is significantly larger than any existing unit equipped with a WESP. Furthermore, the proposed primary fuel, Utah bituminous coal, has sulfur content significantly lower than the sulfur content of fuels typically associated with WESP, such as petroleum coke and high sulfur eastern bituminous coal. In fact, the maximum H_2SO_4 concentration in the Unit 3 flue gas is already expected to be significantly below 10 ppmvd @ 3% O_2, a level generally associated with a controlled H_2SO_4 emission rate.

Even though WESP has not been proven to be capable of reducing H_2SO_4 emissions from a pulverized coal-fired unit similar to IPSC's proposed Unit 3, IPSC included WESP as a potential H_2SO_4 control technology in its NOI and BACT evaluation.

Until recently, WESP technology has not been applied to the utility industry because of the high gas flow volumes and the relatively low acid mist concentrations associated with utility flue gas. WESP has been used successfully in industrial applications such as sulfuric acid plants and municipal waste combustion, which have significantly lower flue gas flow rates and significantly higher acid mist concentrations.

At coal-fired boilers, WESP has generally been used to reduce acid mist concentrations that have contributed to opacity at units firing high sulfur fuels. Sulfuric acid concentrations in the flue gas greater than approximately 5 – 10 ppm may contribute to visible plume from the stack. It is not expected that an acid mist concentration of 1.5 ppmvd @ 3% O_2 will contribute to opacity. Thus, no environmental benefit due to reduced opacity would be expected to occur with installation of WESP.

While a WESP system has not been directly proven to be capable of reducing H_2SO_4 emissions from a pulverized coal-fired unit similar to IPP's proposed Unit 3, the maximum control efficiency (based on the anticipated flue gas H_2SO_4 concentration) would not be expected to be greater than approximately 80% under optimal conditions. This control efficiency would result in a controlled H_2SO_4 emission rate of approximately 0.00088 lb/MMBtu, reducing the flue gas H_2SO_4 concentration to approximately 0.30 ppmvd @ 3% O_2, and represents an overall control efficiency (with FF + wet FGD + WESP) of approximately 98%.

Economic Evaluation

Table 3 presents the projected capital costs and annual operating costs associated with building and operating a WESP system to control H2SO4 mist from a nominal 950-gross MW unit. Table 4 shows the average annual cost effectiveness for the WESP, assuming 70% post-wet FGD H_2SO_4 control.

Table 3
H_2SO_4 Emission Control System
Cost Summary*

Control Technology	Total Capital Investment ($)	Total Capital Investment ($/kW)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
WESP	$58,290,000	$63	$7,319,800	$6,857,100	$14,176,900

* Capital costs provided in Table 1 are based on the average purchased equipment cost provided by four WESP vendors plus typical cost factors attributable to pollution control equipment.

Table 4
H_2SO_4 Emission Control System
Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)
WESP	$14,176,900	139*	$101,990

* Annual emissions were calculated based on a controlled emission rate of 0.0044 lb/mmBtu (174 tpy) with the FF plus wet FGD configuration, and 0.00088 lb/mmBtu (35 tpy) with the WESP configuration.

In addition, WESP consumes power equivalent to 1.5% of the station output or in this case 130 MW which would result in significant increase in coal consumption and corresponding increases in emissions of other pollutants.

Based on the technical infeasibility, UDAQ has concluded that WESP should be excluded from consideration as BACT. Even if WESP were technically feasible based on economic impact, the cost effectiveness of a WESP system designed to reduce the post-wet FGD H_2SO_4 emission rate by 80% is approximately $101,990/ton (which exceeds the cost effectiveness guidelines used in prior BACT determinations) and is not cost warranted.

Fabric filtration and wet FGD have been proposed as BACT for PM_{10} and SO_2 control, respectively, because they provide the most stringent emission control. Based on stack tests on IPP Unit 1, this combination of control technologies is expected to reduce potential H_2SO_4 emissions by approximately 90%. Emission reduction is achieved in the fabric filter cake because of the alkalinity of the Utah coal, and additional control is achieved in the wet FGD. Assuming a control efficiency of 90%, the controlled H_2SO_4 emission rate will be 0.0044 lb/MMBtu (or approximately 1.5 ppmvd @ 3% O_2). It is not expected that an acid mist concentration of 1.5 ppmvd @ 3% O_2 will contribute to opacity from the proposed unit.

Step 3

Emission rates for each of the technically feasible H_2SO_4 removal technologies are ranked in order of their control effectiveness. These effectiveness values are provided in the table below.

H_2SO_4 Control Technology Emission Rate Ranking

Control Technology	H_2SO_4 % Reduction [a]
Fabric Filter + Wet Limestone Scrubbing + Wet Electrostatic Precipitation	Approximately 98%
Fabric Filter + Wet Limestone Scrubbing	Approximately 90%

[a] Estimated maximum H_2SO_4 emission control efficiencies listed in the table are the results of stack testing on IPP's existing Unit 1, and engineering estimates.

Step 4

This step involves the consideration of energy, environmental, and economic impacts associated with each technically feasible control technology. The top-down process requires that the evaluation begin with the most effective technology. For the new generating unit, the top H_2SO_4 control technology consists of a combination of fabric filter, wet limestone scrubbing, and wet electrostatic precipitation. This combination of control technologies will reduce potential H_2SO_4 emissions by approximately 98 percent. The second most effective combination of control technologies consists of fabric filter plus wet limestone scrubbing. This combination of control technologies will reduce potential H_2SO_4 emissions by approximately 90 percent.

Both combinations of control systems will result in collateral environmental impacts. For example, both systems will consume water and generate coal combustion wastes that must be managed and disposed of in a landfill. When comparing both combinations of controls, wet electrostatic precipitation will result in increased water consumption and energy consumption. However, the collateral environmental impacts associated with wet electrostatic precipitation do not exclude it from consideration as BACT.

Therefore, it is necessary to evaluate each combination of control systems for economic impacts. Assuming that a wet electrostatic precipitation system is technically feasible, the cost effectiveness of a WESP system designed to reduce post-FGD H_2SO_4 additional emissions by 80% is more than $100,000 per ton. This cost effectiveness exceeds the cost effectiveness guidelines used by UDAQ in prior BACT determinations.

Step 5

The final step in the top-down BACT analysis process is to select BACT.

The following table is: Recently Issued PSD Permits – H_2SO_4 Limits

Name	Type/Size	H_2SO_4 Limit	Control Equip.
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	No Limit	Dry Lime FGD
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.0115 lb/MMBtu	Dry Lime FGD
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	No Limit	Dry Lime FGD
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.00497 lb/MMBtu	Wet Limestone FGD + Wet Electrostatic Precipitation
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.00463 lb/MMBtu	Dry Lime FGD
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.0064 lb/MMBtu	Dry Lime FGD
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.0061 lb/MMBtu	Dry Lime FGD
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	No Limit	Wet Lime FGD
Prairie State Units 1 and 2, Illinois	Pulverized Coal 750 MW each	0.0050 lb/MMBtu	FF, Wet Limestone FGD, WESP
Council Bluffs Energy Center Unit 4, Iowa	Pulverized Coal 750 MW	0.0042 lb/MMBtu	Lime Spray Dryer, FF
Cross Units 3 and 4, South Carolina	Pulverized Coal 600 MW each	0.0014 lb/MMBtu (365-day rolling avg)	Wet Limestone FGD
Longview Energy Center, West Virginia	Pulverized Coal 600 MW	0.0075 lb/MMBtu	Baghouse, Wet Limestone FGD
Elm Road Generating Station, Units 1 and 2, Wisconsin	Pulverized Coal 600 MW, each (6,180 MMBtu/hr)	0.10 lb/MMBtu (24-hour average)	Wet Limestone FGD and Electrostatic Precipitator

In most permits listed in the above table, the technology identified as BACT for the control of H_2SO_4 is the same control technology identified as BACT for the control of SO_2. The only exception is the proposed Thoroughbred facility that included wet electrostatic precipitation to control H_2SO_4

emissions. However, the proposed Thoroughbred facility will be fired on high-sulfur midwestern bituminous coal (4.24% S by weight). Based on information available in the Thoroughbred permit application, the potential uncontrolled SO_2 emission rate at Thoroughbred is approximately 8.51 lb/MMBtu. This emission rate is more then five times the uncontrolled SO_2 emission rate at IPA Unit 3. This high SO_2 concentration will result in significantly more SO_3 and H_2SO_4, and could contribute to acid mist opacity problems at the facility. Therefore, a wet electrostatic precipitation system may be required to address potential opacity issues, and the control efficiency of a wet electrostatic precipitation system will be more reasonable for a system fired on high-sulfur coal.

In the BACT section for SO_2 it was concluded that wet limestone scrubbing would provide the most stringent SO_2 emission control on proposed Unit 3, and that wet limestone-scrubbing represents BACT for the control of SO_2. Based on stack test conducted at the existing IPP station, it has been determined that the combination of fabric filters and wet scrubbing will also reduce potential H_2SO_4 emissions by approximately 90%. This combination of technologies will reduce the H_2SO_4 emission rate to approximately 174 lb/hr, or 0.0044 lb/MMBtu. This emission rate is already below the emission rates listed in the above table. Although wet electrostatic precipitation may provide some incremental reduction in H_2SO_4 emissions, the cost associated with the incremental emission reduction is not warranted. Also, based on the analysis presented earlier, it can be concluded that WESP has not been proven as a technically feasible control option to reduce H_2SO_4 missions from a large pulverized coal-fired unit fired on low sulfur bituminous coal. Therefore, the combination of fabric filter and wet limestone scrubbing and the limit of 0.0044 lb/MMBtu is proposed as BACT for the control of H_2SO_4 on 24-hour block average, excluding SSM periods.

The BACT analysis for NO_x

NO_x Analysis

NO_x will be emitted by combustion of coal in the boiler. NO_x is formed in the combustion process when the peak flame temperature reaches a sufficiently high temperature (approximately 2,500ºF). The first step is to evaluate NO_x controls determined to be BACT by permitting agencies across the United States. This information is available from the EPA RBLC database. Additional technology reviews from sources including EPA's NSR bulletin board, BACT guideline – South Coast Air Quality Management District, control technology vendors, technical journals and web sites, and other recently issued federal/state/local NSR permits.

Step 1

Potential NO_x control technology options applicable to coal-fired boilers are:

- SCR
- Selective noncatalytic reduction (SNCR)
- LNB with overfire air
- LNB
- Good combustion control
- Flue gas recirculation

Step 2

All of these technologies except flue gas recirculation are deemed to be feasible. Flue gas recirculation is an older technology that is not very effective in controlling NO_x on coal-fired units. Therefore it is eliminated as not being technically feasible. SNCR has not been proven on coal-fired units using the specific type of coal proposed for Unit 3. Based on consultation with manufacturers, from a technical point of view, and with the successful operating history at other facilities, SCR is being proposed for use on this project.

Step 3

Emission rates for each of the remaining technology combinations are required to rank them in order of effectiveness. These emission rates are provided in the table below. The control efficiencies are from the RBLC database and are provided in the IPSC NOI dated May 14, 2003, Appendix F, Table F-9.

NO_x Control Technology Emission Rate Ranking

Control Technology	NO_x Emission Rate [a]
SCR	0.07 – 0.15
SNCR	0.12 - 0.25
LNBs with Overfire Air	0.15 – 0.33
LNBs	0.32 – 0.39
Combustion Controls	0.23 – 0.55
NSPS Limit	0.16[b]

[a] Pounds per MMBtu as found in the RBLC database.
[b] Converted from NSPS limit of 1.6 pounds per MWhr assuming a heat rate of 10,000 Btu per kWh. The NSPS regulations require that BACT be no higher than emissions limits contained in the NSPS. Because there is an NSPS that applies to the boilers, that NSPS emission limit is included in the ranking.

Step 4

SCR with LNBs and overfire air is being proposed for this project. SCR is a control technique that reacts ammonia with the NO_x in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen.

SCR has two well-documented environmental impacts associated with it, emissions of unreacted ammonia and disposal of spent catalyst. Some ammonia emissions (called ammonia slip) from an SCR system are unavoidable because of imperfect distribution of the reacting gases and ammonia injection control limitations. Also, the NO_x removal efficiency depends on the ratio of ammonia to NO_x. Increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 5 ppmv or less. Ammonia emissions are of concern because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case, reduced NO_x emissions, as an environmental benefit would be traded for increased ammonia emissions as an environmental detriment.

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

The use of SCR may result in increased SO_2 to SO_3 oxidation, which would result in a higher inlet concentration of H_2SO_4 entering the wet limestone FGD system. However, the FGD system will remove a significant portion of the H_2SO_4 prior to stack discharge.

There are also significant cost impacts associated with SCR. Since the use of SCR is thought to represent the most effective NO_x control technique that can be applied to PC-fired boilers, no economic evaluation is necessary.

Step 5

The final step in the top-down BACT analysis process is to select BACT. EPA's RBLC database and other recently issued permits were again consulted to assist in selecting BACT for this project. The NO_x BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in the table below.

Recently Issued PSD Permits – NO_x Limits

Name	Type/Size	NO_x Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.08 lb/MMBtu (30 day rolling avg) 0.10 lb/MMBtu (24 hour avg)	Low-NO_x Burners with SCR Initial limit of 0.12 lb/MMBtu for first 36 months
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	1.6 lb/gross MWh (30 day rolling avg) 9,600 tpy Units 1-4	Low-NO_x Burners with SCR Netted with Units 1 and 2 – no increase in facility NO_x emissions
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.08 lb/MMBtu (30 day rolling avg)	Low-NO_x Burners with SCR Initial limit of 0.12 lb/MMBtu for first 18 months
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.08 lb/MMBtu (30 day rolling avg)	Low-NO_x Burners with SCR
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.07 lb/MMBtu (30 day rolling avg)	Low-NO_x Burners with SCR
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.07 lb/MMBtu (24 hour avg) 0.10 lb/MMBtu (1 hour avg)	Low-NO_x Burners with SCR

Name	Type/Size	NO_x Limit	Control Equipment
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.09 lb/MMBtu (24-hr rolling avg)	Low-NO_x Burners with SCR Draft Permit
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.09 lb/MMBtu (30 day rolling avg)	Low-NO_x Burners with SCR
Prairie State Units 1 and 2, Illinois	Pulverized Coal 750 MW each	0.08 lb/MMBtu (30-day rolling avg)	Low-NO_x Burners with SCR
Council Bluffs Energy Center Unit 4, Iowa	Pulverized Coal 750 MW	0.07 lb/MMBtu (30-day rolling avg)	Low-NO_x Burners with SCR
Cross Units 3 and 4, South Carolina	Pulverized Coal 600 MW each	0.08 lb/MMBtu (365-day rolling avg)	Low-NO_x Burners with SCR
Longview Energy Center, West Virginia	Pulverized Coal 600 MW	0.08 lb/MMBtu (24-hr avg)	Low-NO_x Burners with SCR

All the permits above exempt startup, shutdown and malfunction in the short-term (1 hour, 24 hour and 30 day) emission limits.

Of the projects found, only SCR is shown to meet NSPS. The installation of LNBs, OFA, and SCR on IPP Unit 3 will result in a NO_x outlet emission rate of 0.07 lb/MMBtu. This is lower than any project listed in the RBLC and as low as any of the recently issued permits that were reviewed for coal-fired utility boilers as outlined in the above table. Therefore, LNBs and SCR are selected as BACT for this project with an emission limit of 0.07 lb/MMBtu based on a 30-day rolling average excluding SSM periods.

The BACT analysis for CO and VOCs Emissions

Step 1

Only two control technologies have been identified for control of CO and VOC on coal-fired boilers:

- Catalytic oxidation
- Combustion controls

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

Step 2

Catalytic oxidation has been the control alternative used to control CO and VOCs emitting from combustion turbines firing primarily natural gas.

Technical feasibility requires a two-part analysis: 1) is an oxidation catalyst “available” for application to a PC boiler, and 2) is an oxidation catalyst technically feasible on a PC boiler.

Availability

According to EPA policy, a technology is considered available if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. However, technologies that are in the research and development stage, patent stages, or pilot scale stages are not considered available. Moreover, technologies that would result in extended downtime, resource penalties, or take extended trials to apply are not considered available for a proposed project. According to the applicant, this type of oxidation catalyst technology has never been applied to a PC-fired unit. Concerns exist over the ability to design and operate (long-term) a catalyst that would achieve consistent VOC and CO reductions.
For sulfur containing fuels, such as coal, an oxidation catalyst will convert SO_2 to SO_3 and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system. Generally, oxidation catalysts are designed for a maximum particulate loading of 50 milligrams per cubic meter (mg/m^3). The proposed IPP Unit 3 boiler will have a particulate loading upstream of the fabric filter in excess of 5,000 mg/m^3. In addition, trace elements present in coal, in particular chlorine, are poisonous to oxidation catalysts. There are no catalysts developed that have or can be applied to PC-fired boilers due to the high levels of PM and trace elements present in the flue gas. These concerns would have to be addressed through system trials prior to application of this control technology to the proposed boiler. Consistent with EPA policy, control systems that would require considerable trial time to apply are not considered available within the context of a technology determination.

Technically Feasible

For the same reasons cited above (particulate loading and flue gas characteristics, the use of an oxidation catalyst) is not considered technically feasible at this time. Although the catalyst could be installed downstream of the fabric filter where the concentration of PM in the flue gas is much lower than at the outlet of the boiler, the flue gas temperature at that point will be approximately 300°F. This is well below the minimum temperature required (600°F) for operation of oxidation catalyst. The flue gas would have to be reheated, resulting in significant unfavorable energy and economic impacts.

Step 3

Based on the Step 2 analysis, combustion control is the only remaining technology for this application.

Step 4

There were no adverse environmental or energy impacts associated with combustion control.

Step 5

Recently Issued PSD Permits - CO Limits

Name	Type/Size	CO Limit	Comments
Hawthorne Unit 5	Pulverized Coal	0.16 lb/MMBtu	Combustion control

Missouri	570 MW		CEMS not required Stack test used for compliance
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.15 lb/MMBtu (30 day rolling average)	Combustion control CEMS used for compliance
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.15 lb/MMBtu	Combustion control CEMS not required Stack test used for compliance If CO and NO_x limit cannot be met simultaneously, State will revise CO limit
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.10 lb/MMBtu (30 day rolling avg)	Combustion control CEMS used for compliance
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.15 lb/MMBtu	Combustion control CEMS not required Stack test used for compliance
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.15 lb/MMBtu	Combustion control CEMS not required Stack test used for compliance
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.16 lb/MMBtu	Combustion control CEMS used for compliance
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.15 lb/MMBtu	Combustion control CEMS not required Stack test used for compliance
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.154 lb/MMBtu (1 day avg) 5,177 tpy	Combustion control CEMS used for compliance If CO and NO_x limit cannot be met simultaneously, State will revise CO limit
Elm Road Generating Station, Units 1 and 2 Wisconsin	Pulverized Coal 600 MW each (6,180 MMBtu/hr)	0.12 lb/mmbtu (24-hr rolling avg)	Combustion control. CEMS used for compliance. Emission limit excludes startup and shutdown. Other limits: 742 lb/hr CO 24-hr rolling average, 2,400 lb/hr CO 1-hr average, 3,250 tons 12 month rolling total (includes all operation, startup and shutdown).
Longview Power	Pulverized Coal	0.11 lb/MMBtu	Combustion control.

Unit 1 West Virginia	600 MW (6,114 MMBtu/hr)	(3-hr rolling avg)	CEMS used for compliance.
Prairie State Generating Station Units 1 and 2 Illinois	Pulverized Coal 750 MW each (7,450 MMBtu/hr)	0.12 lb/MMBtu (24 hour block avg)	Draft Permit Combustion control. CEMS used for compliance.

All the permits above, except Bull Mountain Roundup and Elm Road Generating Station, exempt startup, shutdown and malfunction in the short-term (1 hour, 3 hour, 24 hour and 30 day) emission limits.

The BACT analysis in the IPP permit application concluded that combustion control was the appropriate control technology with an emission limit of 0.15 lb/MMBtu. This is equivalent to a boiler outlet concentration of 180 ppmvd at full load with the range of coals designed for the unit. It is expected that this will be the emission rate guarantee by boiler equipment vendors. IPP proposes to demonstrate compliance with this limit based on initial performance stack testing and the use of CEM or a CEM equivalent method, such as parametric monitoring, as determined by the Executive Secretary.

The table of CO limits for other recently issued pulverized coal-fired utility boilers PSD permits has been updated with three new units. They are shown in Table 1. Note that the Prairie State permit is still in draft form. Eight of the twelve facilities burn either Powder River Basin (PRB) western subbituminous coal or western bituminous coal. These facilities include Hawthorne, Springerville, Holcomb, Wygen, Roundup, Plum Point, Hardin and Council Bluffs. These facilities have CO permit limits between 0.15 and 0.16 lb/MMBtu. The remaining four facilities on the list burn eastern bituminous coals with significantly higher fuel heating values. These facilities include Thoroughbred, Elm Road, Longview and Prairie State. These facilities have CO permit limits between 0.10 and 0.12 lb/MMBtu. Five of the twelve units will use stack testing to demonstrate compliance with the limit; the other seven will utilize a CO CEM to demonstrate compliance.

To date, boiler vendors have supplied CO guarantees in the range of 0.15 – 0.16 lb/MMBtu for new pulverized coal boilers that burn western coals. The facilities that have lower permit limits are all designed to burn eastern bituminous coal. Of all the recently issued permits, only Hawthorne Unit 5 is operational and has demonstrated compliance with a 0.16 lb/MMBtu CO permit limit.

For the reasons stated above, IPP proposed that a CO limit of 0.15 lb/MMBtu and the use of initial stack testing and CEM or CEM equivalent method for compliance demonstration is appropriate BACT for IPP Unit 3. As referenced in the March 25, 2004 letter from CH2M HILL to UDAQ, IPP is agreeable to a 30-day block average CO limit of 1,390.6 lb/hr (0.15 lb/MMBtu at the maximum boiler heat input of 9,050 MMBtu/hr) and a short-term 8-hour CO emission limit of 3,000 lb/hr. The modeling conducted for IPP Unit 3 demonstrated that the CO impacts are well below the Class II modeling significance levels for both the 1-hour and 8-hour CO standards.

Recently Issued PSD Permits - VOC Limits

Name	Type/Size	VOC Limit	Comments
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.0036 lb/MMBtu	Combustion control Stack test used for compliance

Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.06 lb/ton coal (3 hour average)	Combustion control Stack test used for compliance
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.0035 lb/MMBtu	Combustion control Stack test used for compliance If VOC and NO_x limit cannot be met simultaneously, State will revise VOC limit
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.0072 lb/MMBtu (30 day rolling avg)	Combustion control Compliance with CO limit used to demonstrate compliance with VOC limit
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.01 lb/MMBtu	Combustion control Initial Stack test used for compliance
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.0030 lb/MMBtu	Combustion control Stack tests not required
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 – 800 MW	0.02 lb/MMBtu	Combustion control Stack test used for compliance
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.0034 lb/MMBtu	Combustion control Stack tests not required
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.0036 lb/MMBtu	Combustion control Initial Stack test used for compliance
Elm Road Generating Station, Units 1 and 2 Wisconsin	Pulverized Coal 600 MW each (6,180 MMBtu/hr)	0.0035 lb/MMBtu (24-hr rolling avg)	Combustion control. Initial Stack test used for compliance. Emission limit excludes startup and shutdown.
Longview Power Unit 1 West Virginia	Pulverized Coal 600 MW (6,114 MMBtu/hr)	0.004 lb/MMBtu (3 hr rolling avg)	Combustion control. Stack tests used for compliance.
Prairie State Generating Station Units 1 and 2 Illinois	Pulverized Coal 750 MW each (7,450 MMBtu/hr)	0.004 lb/MMBbtu (3 hr block avg)	Draft Permit Combustion control. Stack tests used for compliance.

All the permits above, except Bull Mountain Roundup and Elm Road Generating Station, exempt startup, shutdown and malfunction in the short-term (1 hour, 3 hour, 24 hour and 30 day) emission limits.

The BACT analysis in the IPP permit application concluded that combustion control was the appropriate control technology with an emission limit of 0.0027 lb/MMBtu on 3- test run average and annual stack test utilizing EPA Referenced Method 25 or 25A.

VOC limits in other recently issued PSD permits for pulverized coal-fired utility boilers are shown in Table 2. The twelve permits have limits between 0.0030 and 0.0200 lb/MMBtu depending on the boiler type and design coal. Nine of the twelve units will use initial stack testing to demonstrate compliance with the limit; the other three do not require compliance demonstration.

The IPP Unit 3 proposed VOC limit of 0.0027 lb/MMBtu is lower than any of the other recently issued permits. Therefore, a VOC limit of 0.0027 lb/MMBtu on 3-test run average for an initial and annual stack test for compliance is demonstration is BACT.

The estimated emissions of CO and VOCs on IPP Unit 3 boiler are among the lowest of the emissions shown for applicable projects in the RBLC or other recently issued permits. The final step in the top-down BACT analysis process is to select BACT.

Based on the above analysis, combustion control for CO and VOCs is selected as BACT for this project with emission limits of 0.150 lb/MMBtu on 30-day rolling average for CO (monitored with CEM) and 0.0027 lb/MMBtu on 3-hour stack test average (monitored with annual stack testing) for VOCs.

PM and PM_{10} BACT Analysis

PM and PM_{10} emissions will be emitted from the boiler, cooling towers, and the coal, limestone, ash, and sludge handling systems. An analysis for the emissions from the boiler is presented, followed by an analysis for the cooling towers followed by analyses of the coal, limestone, sludge, and ash handling systems.

PM and PM_{10} Analysis for Boiler

Step 1

Two control technologies for coal-fired boilers have been identified for PM and PM_{10} control:

- Electrostatic precipitators (ESPs)
- Fabric filters

Step 2

ESPs**.** ESP technology is applicable to a variety of coal combustion sources. ESPs remove PM from the flue gas stream by charging fly ash particles with a very high dc voltage and attracting these particles to grounded collection plates. A layer of collected particles forms on the collecting plates and is removed by rapping the plates. The collected ash particles drop into hoppers below the precipitator and are periodically removed by the fly ash handling system.

Fabric Filters. Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

Fabric filtration is a constant-emission control device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric-filter depends on specific items such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particles (e.g., irregular-shaped or spherical), particle size distribution, and to some extent, the frequency of the cleaning cycle.

Fabric filter system design involves inlet loading rates, fly ash characteristics, the selection of the cleaning mechanism, and selection of a suitable filter fabric and finish. Specific design parameters cannot be established until the actual fabric filter manufacturer is determined; however, the fabric filter system will be designed to achieve a filterable PM_{10} emission rate no greater than 0.015 lb/MMBtu, which represents a control efficiency of 99.825 percent.

Fabric filters are effective in meeting NSPS emission requirements on PC-fired boilers. Fabric filters have been used as a control technology of choice on projects where lowest achievable emissions reduction (LAER) review is required. Unlike ESPs, fabric filter design is not based on any physical properties of the fly ash.

Step 3

The fabric filter is more effective at capturing fine particulate than an ESP because ESPs tend to selectively collect larger particles. Large particles have a high mass to surface area ratio, which allows a charged particle to be efficiently dragged through the flue gas stream for collection on a charged plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection. The fabric filter is also more effective at collecting fly ash generated from western low sulfur coals such as those combusted at IPP. ESPs operate by first electrostatically charging for collection and then discharging the fly ash particles for removal in the ash handling system. Western low sulfur coal fly ash has a very high electrical resistivity that makes it difficult for the ESP to charge and then discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800ºF as opposed to the approximately 250ºF operating temperature used on most ESPs. Another solution has been to inject a flue gas-conditioning agent to alter the resistivity of the fly ash. However, even with this change in operating temperature or the injection of a conditioning agent, the ESP is still less effective than a fabric filter at collecting fly ash in western power plants.

Step 4

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from PC-fired boilers. There is, however, a high-energy demand for this system. Energy is required to operate large fans to overcome the complete system's (fabric filter and associated ductwork) 8- to 12-inch water gauge pressure drop, and miscellaneous loads such as electric hopper heating. As baghouse filters are thought to represent the most effective PM and PM_{10} control technique that can be applied to PC-fired boilers, no economic evaluation is warranted.

Step 5

The fabric filter proposed for IPP Unit 3 will have a design collection efficiency of 99.825 percent. The PM_{10} BACT limits from other recently issued PSD permits for PC-fired boilers are summarized in the table below.

Recently Issued PSD Permits – PM_{10} Limits

Name	Type/Size	PM_{10} Limit	Control Equipment
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.018 lb/MMBtu 20% Opacity	Fabric Filter Compliance based on annual test Condensable PM_{10} not specified
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.015 lb/MMBtu (PM) (3 hour rolling avg) 0.055 lb/MMBtu (PM_{10}) (3 hour rolling avg) 15% Opacity	Fabric Filter Compliance based on annual test PM limit is filterable only. PM_{10} limit includes filterable and condensable
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.018 lb/MMBtu 20% Opacity	Fabric Filter Compliance based on 3 2-hr stack tests Condensable PM_{10} not specified
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.018 lb/MMBtu (3 hour avg) 20% Opacity	Electrostatic Precipitator Limit includes both filterable and condensible
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.012 lb/MMBtu 20% Opacity	Fabric Filter Limit is filterable PM_{10} only
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.015 lb/MMBtu 20% Opacity	Fabric Filter Limit may be reduced to 0.012 lb/MMBtu based on performance test Condensable PM_{10} not specified
Plum Point Energy Station Units 1 and 2 Arkansas	Pulverized Coal 550 – 800 MW each	0.018 lb/MMBtu 10% Opacity	Fabric Filter Limit includes filterable and condensible

Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.015 lb/MMBtu	Multiclones and Wet Lime FGD Limit is filterable PM_{10} only
Prairie State Units 1 and 2, Illinois	Pulverized Coal 750 MW each	0.015 lb/MMBtu	ESP Limit is filterable PM only
Council Bluffs Energy Center Unit 4, Iowa	Pulverized Coal 750 MW	0.025 lb/MMBtu 0.018 lb/MMBtu (PM)	Fabric filter PM10 limit includes filterable and condensible
Cross Units 3 and 4, South Carolina	Pulverized Coal 600 MW each	0.018 lb/MMBtu 0.015 lb/MMBtu (PM)	ESP PM10 limit includes filterable and condensible
Longview Energy Center, West Virginia	Pulverized Coal 600 MW	0.018 lb/MMBtu	ESP Limit includes filterable and condensible
Elm Road Generating Station, Units 1 and 2, Wisconsin	Pulverized Coal 600 MW each (6,180 MMBtu/hr)	0.018 lb/MMBtu (any consecutive 3-hour period)	Test Methods 5/4B and 202 for compliance demonstration
All the permits above, except Bull Mountain Roundup Unit 1 exempt startup, shutdown and malfunction in the short term (lb/MMBtu) emission limits.			

IPSC submitted several papers with detailed operational and cost analysis comparing the application of baghouse with oven fiberglass bags, Ryton-type bags and polytetrafluorethylene (PTFE)-membrane coated bags (also called as Gore-Tex specialty bags).

The average cost effectiveness of the fabric filter system equipped with specialty bags will be approximately 20 – 25% more expensive than the same system equipped with woven fiberglass or Ryton-type bags. Because of the large quantity of PM_{10} removed by the fabric filter, a 20% increase in cost effectiveness is significant.

Based on the IPSC analysis, the specialty bag system were only proposed on the Wyoming Wygen Unit 2 and PTFE-coated bags have not been used extensively on pulverized coal-fired boilers so they have only marginally been demonstrated in practice in this application.

Detailed comparison was performed by IPSC and the following are some of the highlights of it:

Sulfuric acid mist is another PSD pollutant that may be controlled in the fabric filter. However, with respect to H_2SO_4 and other acid gases (e.g., HCl and HF) it is not expected that the type of filter used in the fabric filter will impact acid gas removal. Acid gases are removed as the flue gas passes through the alkaline filter cake that accumulates on the filter bag. Therefore, acid gas removal is a function of the thickness and alkalinity of the filter cake. Filter cake properties, including thickness and alkalinity, are not of function of the bag material. Therefore, changing to specialty coated filter bags is not expected to increase the system's acid gas removal efficiency (major portion of the condensable emissions).

Based on a unit size of 500 MW (gross), the incremental annual cost increase at Wygen Unit 2 would be approximately $1.59/kW-gross. Wygen Unit 2 has not yet been constructed, so the Wygen Unit 2 cost estimate was probably based on 2002 design costs.

In the IPP Unit 3 cost estimate the incremental cost increase associated with using specialty bags was calculated to be $1,669,100/year ($757,200 capital recovery cost plus $911,900 O&M). Based on a 950 MW-gross output, the cost increase per kw-gross would be $1.76/kW-gross. Although this is approximately 10% higher than the cost estimate at Wygen 2 it is well within the margin of a budgetary cost estimate.

In addition to the incremental difference in bag material cost, there are other significant differences between the Wygen 2 and IPP Unit 3 PM_{10} BACT determinations. First, Wygen 2 proposed a 500 MW-gross pulverized coal fired boiler compared the IPP's 950 MW-gross boiler. Based on unit size and flue gas flow rates, the IPP Unit 3 baghouse will be significantly larger than the Wygen 2 baghouse. Second, Wygen 2 will burn a subbituminous coal and use a spray dry absorber (SDA) for SO_2 control. IPP Unit 3 will primarily burn a Utah bituminous coal and proposed a wet scrubber for SO_2 control; a wet scrubber provides more stringent SO_2 control than an SDA. As discussed in IPP's NOI, an SDA is typically located upstream of the baghouse while a wet scrubber is located downstream of the baghouse. Because of the location of the scrubber, the IPP Unit 3 baghouse will see higher flue gas temperatures, and there will be a corresponding slight increase in particulate emissions from dissolved solids in the wet FGD scrubber slurry. On the other hand, the IPP wet scrubber provides the most stringent SO_2 control.

Finally, in its BACT determination Wygen 2 assumed that the lowest emission rate it could achieve with Ryton-type bags was 0.018 lb/MMBtu. IPSC has received information that baghouse vendors may be willing to guarantee a PM_{10} emission rate of 0.015 lb/MMBtu without using specialty coated bags (based on the IPP Unit 3 design). Wygen 2 concluded that membrane bags would be required to achieve either 0.015 or 0.012 lb/MMBtu (presumably for the Wygen 2 design). Therefore, the Wygen 2 incremental cost comparison between 0.018 lb/MMBtu and 0.012 lb/MMBtu resulted in an incremental cost effectiveness of $5,846/ton. Even though this cost effectiveness is significantly greater than the cost typically associated with PM-10 control, WDEQ considered the "incremental cost effectiveness to be reasonable for 0.012 lb/MMBtu…"

BACT is an emission limitation based on a case-by-case review of emission control technologies taking into account site-specific energy, environmental and economic costs associated with each alternative technology. Based on site-specific design criteria including boiler design, flue gas flow rate, flue gas temperature, uncontrolled particulate loading, sulfur dioxide control configuration, and bag material costs, IPP concluded that an emission rate of 0.012 lb/MMBtu may be technically feasible, however the incremental cost of reducing PM-10 emissions from 0.015 to 0.012 lb/MMBtu (approximately $14,000 - $16,000/ton) represents an adverse economic impact. This impact, combined with the energy impacts discussed above, resulted in the conclusion that $PM\text{-}_{10}$ BACT for this project is 0.015 lb/MMBtu (3-test run average).

In other words, the cost of removing the first 339,400 tons of PM10 is approximately $31/ton, while the cost of removing the last 119 tons increases to $15,800/ton. The incremental cost increase associated with the lower emission limit is disproportionately high.

The specialty bag system may reduce annual PM_{10} emissions by approximately 119 tons at a cost ranging from $1.67 to $1.94 million dollars. This results in an incremental cost effectiveness of approximately $14,000 to $16,350 per ton.

<u>Effect on the cost analysis of Calculation of the Uncontrolled PM_{10} Emission Rate</u>

In its PM_{10} BACT analysis, IPA assumed that all particulate matter emitted as fly ash from the boiler would be emitted as PM_{10} (i.e., particulate matter with an aerodynamic equivalent diameter less than 10 microns). On the other hand, the FLM calculated the uncontrolled PM_{10} emission rate based on particulate size distribution in AP-42.

Although the fabric filter will be designed to control all particulate matter emitted from the boiler, it is likely that a certain percentage of the uncontrolled particulate matter will have an aerodynamic diameter greater than 10 microns. Therefore, to calculate the cost effectiveness of the fabric filter (with respect to PM_{10} only) it is appropriate to adjust the uncontrolled particulate emission rate.

AP-42 Section 1.1 includes the following emission factors for uncontrolled PM_{10} from coal-fired boilers:

> Table 1.1-4:
> Filterable PM_{10} = 2.3A lb/ton coal fired
> Where: A = % ash content of coal
> Emission Factor Rating: E
>
> AP-42 Table 1.1-6:
> Cumulative particle size distribution for dry bottom boilers burning pulverized bituminous and subbituminous coal. 23% of the uncontrolled particulate matter will have a particle size 10 microns or below.

The uncontrolled PM_{10} emission rate using each approach is provided below:

		PM = PM_{10}	AP-42 Table 1.1-4	AP-42 Table 1.1-6
Maximum Coal Feed Rate	lb/hr	808,541	808,541	808,541
	ton/hr		404.27	
Ash Content of Fuel	%	12%	12%	12%
Fly Ash : Bottom Ash Ratio	%	80% fly ash		80% fly ash
AP-42 Emission Factor		na	2.3A	23% of PM total
PM10		(808,541 x 0.12) x	2.3 x 12 =	77,620 x 0.23 =

Calculation		0.8 =	27.6 lb/ton	
Uncontrolled PM10 Emission Rate	lb/hr	77,620	11,158	17,853
Uncontrolled PM10 Emission Rate	tpy	339,976	48,872	78,196

The baseline PM_{10} emission rate will affect the calculation of the fabric filter's control efficiency and average cost effectiveness. However, it will not change the controlled emission rate or incremental cost effectiveness.

In order to compare the control efficiency of the proposed Unit 3 fabric filter to other, recently permitted, coal-fired utility boilers, it is appropriate to assume that PM total = PM_{10} (i.e., uncontrolled PM_{10} emission rate = 77,620 lb/hr). This approach is consistent with all other recently permitted utility coal fired boilers. However, to be consistent with the FLM BACT cost calculations, IPA recalculated the average cost effectiveness using the Table 1.1-4 AP-42 emission factor (PM_{10} = 2.3A lb/ton).

Based on the above analysis, the recently issued PSD permits listed in the above table, and the EPA RBLC database (refer to Tables F-3 and F-4 in the IPSC NOI dated May, 14 2003, Appendix F), a fabric filter with a filterable PM emission rate limit of 0.020 lb/MMBtu based on a 3-hour rolling average and a filterable PM_{10} emission rate limit of 0.015 lb/MMBtu (filterable) based on a 24-hour block average, are selected as BACT for this project. No condensible PM_{10} BACT emission rate limit is included instead the H_2SO_4 and filterable PM_{10} limits will be used to serve as surrogate limits that better represent the performance of the control equipment.

Boiler Startup and Shutdown BACT

IPSC Unit 3 is designed as a base load unit and because of it, and based on historical frequency of the startups and shutdowns at the existing Units 1 and 2, it is expected to have very few startups and shutdowns. However, IPSC will perform all startups and shutdowns in accordance with manufacturer's written operating instructions and/or written procedures developed and maintained by IPSC. Startup and shutdown procedures will be designed to minimize all excess emissions of all pollutants, consistent with safe operation of the unit. In addition, startup and shutdown emissions were modeled and the results of the conservative modeling demonstrate that NAAQS will be fully protected during Unit 3 startup/shutdown and the AO permit limits would be protective during these periods.

BACT for Unit 3 Cooling Towers

Step 1

The only control method for reducing PM and PM_{10} emissions from cooling towers is the use of drift eliminators.

Step 2

Drift eliminators are technically feasible for this project and will be used.

Steps 3 – 5

Drift eliminators are the only control method identified for control of PM and PM_{10} emissions from cooling towers. Based on the above analysis and the EPA RBLC database, drift eliminators with a control efficiency of 0.0005 percent (gallons of drift per gallon of cooling water flow) is chosen as BACT for this project.

BACT Analysis for Unit 3 Coal, Limestone, and Ash Handling Systems

Step 1

PM and PM_{10} will be emitted from the handling of the coal for the power plant, the collected ash that results from the combustion process, and limestone that is used as a reagent for the wet scrubber. These emissions are fugitive dust that comes from the various transfer points in the handling systems for these materials and fugitive emissions from the open storage and disposal areas.

The potential technologies that can be used to control the fugitive dust emissions are as follows for various operations:

Coal Pile: Potential control technologies for an active coal storage pile include the use of an enclosed storage barn or the use of water sprays and dust suppression chemicals on an outside pile. Water sprays and dust suppression chemicals are potential control technologies for inactive (long-term storage) coal piles.

Coal Handling: Potential control technologies for coal storage, transfer, and handling operations include the use of enclosures vented to fabric filters. Telescopic chutes can be utilized for coal unloading onto storage piles.

Limestone Handling: Potential control technologies for limestone storage, transfer, and handling operations include the use of enclosures vented to fabric filters. Limestone truck unloading can be performed in enclosures vented to fabric filter.

Fly Ash Handling: Storage silos and associated transfer operations will be vented to fabric filter for control.

Fly Ash/FGD Waste Haul Roads: Potential technologies for control of fugitive emissions on haul roads are the use of paved roads, the use of covered haul trucks, the use of water sprays, the use of dust suppression chemicals, or the use of street sweepers on paved roads.

Step 2

All of the potential control technologies listed in Step 1 are technically feasible.

Step 3

Generally the use of fabric filters where possible is the most effective control option. In locations where fabric filters cannot be used, the use of water sprays and dust suppression chemicals are the most effective control methods.

Step 4

Fabric filters are the control method of choice where the dust source can be completely enclosed in a building. For dust sources that cannot be completely enclosed, the use of water sprays and dust suppression chemicals are the control methods of choice.

There will be no addition to the Units 1 and 2 active coal pile to serve Unit 3 boiler. Chemical binding (dust suppression chemicals) will be used on the inactive (long-term) storage pile.

New and modified coal, fly ash, and limestone handling operations will have enclosures with fabric filters for dust control.

The paved ash haul and unpaved conditioned sludge haul roads will use water sprays and dust suppression chemicals for dust control.

Step 5

Fabric filters and enclosures and 10% opacity limit at the baghouse outlets are selected as BACT for the coal, fly ash, limestone, transfer points, fly ash storage silos and associated transfer operations, and crusher houses on the coal handling system.

For the places where not applicable to use fabric filters and enclosures, such as coal handling, fly ash handling, the rail unloading stock outpile and the active coal storage pile, work practice (use of water sprays) and opacity limit of 20% is selected as BACT. The inactive coal storage pile will be controlled by the application of a chemical binder and opacity limit of 20%. Fabric filters are also BACT for the transfer points and silos on the limestone and ash handling systems. For the haul roads, 20% opacity limit, water sprays with dust suppression chemicals will be used as BACT for dust control.

Lead BACT Analysis

Lead emissions will be emitted from the boiler. Lead will be present as a constituent of the fly ash and control technologies that are effective in controlling PM emissions will also control lead emissions.

Step 1

Two control technologies for coal-fired boilers have been identified for lead control:
- ESPs
- Fabric filters

Step 2

ESPs. ESP technology is applicable to a variety of coal combustion sources. ESPs remove PM from the flue gas stream by charging fly ash particles with a very high dc voltage and attracting these particles to oppositely charged collection plates. A layer of collected particles forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected ash particles drop into hoppers below the precipitator and are periodically removed from the fly ash handling system.

Fabric Filters. Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

Fabric filters are effective in meeting NSPS emission requirements on PC-fired boilers. Fabric filters have been used as a control technology of choice on projects where LAER review is required. Unlike precipitators, fabric filter design is not based on any physical properties of the fly ash.

Step 3

The fabric filter is more effective at capturing fine particulates than an ESP because ESPs tend to selectively collect larger particles. Large particles have a high mass to surface area ratio, which allows a charged particle to be efficiently dragged through the flue gas stream for collection on a charged plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection.

The fabric filter is also more effective at collecting fly ash generated from western low sulfur coals such as those combusted at IPP. ESPs operate by first electrostatically charging for collection and then discharging the fly ash particles for removal in the ash handling system. Western low sulfur coal fly ash has a very high electrical resistivity that makes it difficult for the ESP to charge and discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800ºF as opposed to the approximately 250ºF operating temperature used on most ESPs. However, even with this change in operating temperature, the ESP is still less effective than fabric filters at collecting fly ash in western power plants.

Step 4

No negative environmental impacts have been identified for use of a fabric filter to control particulate emissions from PC-fired boilers. There is, however, a high-energy demand for this system. Energy is required to overcome the complete system's (fabric filter and associated ductwork) 5- to 6-inch water gauge typical pressure drop, and miscellaneous loads such as electric hopper heating. As baghouse filters are thought to represent the most effective PM and PM_{10} control technique that can be applied, no economic evaluation is warranted.

Step 5

Based on the above analysis, the RBLC database, and other recently issued permits, a fabric filter is selected as BACT for the control of lead emissions for this project with an emission rate of 0.00002 lb/MMBtu at 3-hour testing average.

Fluoride Emissions BACT Analysis

Fluoride compounds will be emitted from the boilers from the combustion of coal. The fluoride compounds will be mainly in the gaseous form of HF in the flue gas exiting the boiler.

Step 1

Two control technologies for fluoride control of flue gas from coal-fired boilers have been identified:

- Wet scrubbers
- Spray dryers followed by fabric filters

Step 2

Wet Scrubber**.** Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (i.e., lime or limestone slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel and a bed material to force the mixing of the alkaline reagent and the flue gas. The calcium in the reagent reacts with the fluoride in the flue gas to form calcium fluoride that is removed from the scrubber with the sludge and is disposed.

The creation of sludge from the scrubber does create a solid waste handling and disposal problem. This sludge needs to be handled in a manner that doesn't result in groundwater contamination. Also, the sludge disposal area needs to be permanently set aside from future surface uses since the disposed sludge cannot bear any weight from such uses as buildings or cultivated agriculture.

Spray Dryer Followed by Fabric Filter. Spray dryers operate by flowing the flue gas upward through a large vessel. In the top of the vessel is a rapidly rotating atomizer wheel through which lime slurry is flowing. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas where the fluorides in the flue gas react with the calcium in the lime slurry to form particulate calcium fluoride. This dry material is captured in the fabric filter along with the fly ash and calcium sulfate from the sulfur removal process.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiberglass fabric bags as filters to collect PM. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated PM collected on the fabric of the filter bags. The collected PM forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess PM is removed to the ash collection system.

Step 3

Either control technology will achieve 90 percent or greater control of fluorides.

Step 4

Either approach can achieve 90 percent or greater control of fluorides. No negative environmental impacts have been identified for use of a spray dryer absorber followed by a fabric filter to control fluoride emissions from PC-fired boilers. The use of a wet scrubber has the negative environmental impact of wet sludge disposal.

Step 5

The EPA RBLC database shows six comparable sources related to fluoride. Five of the sources determined that the use of a dry lime scrubber followed by a fabric filter was BACT. The other source selected an ESP followed by a wet limestone FGD system as BACT for fluoride. A number of other units not identified in the RBLC have identified high fluoride removal rates including Units 1 and 2. The EPRI HAP report uses a factor of 97 percent control for units burning western coal and utilizing wet FGD systems.

Based on the technology and RBLC database discussion above, the use of a wet limestone scrubber is selected as BACT for this project with a fluoride /HF emission rate of 0.0005 lb/MMBtu 3-hour testing average.

B

Case-by-Case MACT for HAPs

Background

The new PC-fired boiler will burn western bituminous coal or blend of bituminous and subbituminous coals, and will be equipped with a forced oxidation wet limestone scrubber for acid gas control, fabric filters for fine particulate control, and SCR for NO_x control. Combustion control will be used to minimize products of incomplete combustion (PICs) such as CO and VOCs. This combination of control technology will also provide substantial control of the HAPs emitted from the proposed PC-fired boiler.

Technology regulations under 40 CFR Part 63, Subpart B are applicable to Unit 3 proposed boiler at the IPP facility. These regulations require that Maximum Achievable Technology for hazardous air pollutants or "MACT" must be applied to the new boiler, since it represents a major source of HAP which is constructed or reconstructed after the effective date of the Section 112(g) program.

Pursuant to 40 CFR 63.43(d), case-by-case determinations of MACT must meet the following requirements:

> "(1) The MACT emissions limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the

> emission control which was achieved in practice by the best controlled similar source, as determined by the permitted authority.
>
> (2) Based upon available information, the MACT emission limitation and control technology…. recommended by the applicant and approved by the permuting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the cost of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction."

As with BACT, an enforceable limit representing MACT must be included in the permit. This emission limitation must be enforceable as a practical matter. In order for emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedure (i.e. monitoring requirements) designed too show compliance or non-compliance or non-compliance on a time period consistent with the applicable emission limit.

The selection of specific hazardous air pollutants to be covered under the MACT analysis was based upon a review of the pollutants expected to be emitted by the proposed boilers and upon MACT rulemakings undertaken by EPA for source categories with similar emission characteristics. Four classes of hazardous air pollutants were identified:

- Mercury – Mercury and its compounds require a separate grouping for MACT limitation because of the unique chemical and physical properties of mercury with respect to air pollution control.

- Fine-particulate HAPs - Fine-particulate HAPs include the heavy metals, including but not limited to arsenic (semi-volatile), cadmium, and chromium (non-volatile), radionuclides, and polycyclic organic matter (POM).

- Acid-Gas HAPs – namely hydrogen fluoride and hydrogen chloride; and products of incomplete combustion, namely polychlorinated biphenyls (PCB), polychlorinated dibenzo-p-dioxins (PCDD), and polychlorinated dibenzofurans (PCDF).
- Organic HAPs
-

One practical way to address the large number of non-mercury HAPs emitted by coal fired boilers is through surrogates:

- Fine-particulate HAPs by fine-particulate mass emissions
- POM by CO surrogate, the traditional and most common indicator of a good combustion control.
- Acid-Gas HAPs by SO_2 emissions.
- Organic HAPs by CO surrogate, the traditional and most common indicator of a good combustion control. Special emphasis needs to be placed during testing on evaluating the relationship between temperatures and the concentrations of CO and organic HAPs.

Unlike BACT, there is little guidance establishing the procedure by which a case-by-case MACT determination is made. For the purposes of this analysis, the Department used a procedure similar to the top-down BACT analysis procedure outlined above.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/ LAER Clearinghouse maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
- Information provided by pollution control equipment vendors.
- Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/ LAER Clearinghouse.

The case-by-case MACT analysis and proposed MACT determinations for the new Unit 3 boiler are discussed in the following paragraphs:

For electric utility steam generating units, the case-by-case provisions contain an exemption from applicability "unless and until such time as these units are added to the source category list." On December 14, 2000, the EPA announced that it was adding PC-fired power plants to the Section 112(c) list of sources (65 FR 79825 published December 20, 2000). Therefore, each PC-fired electric utility steam generating unit, which is constructed or reconstructed, is now subject to the case-by-case provisions of the Act until the EPA promulgates a nationally applicable MACT standard to address HAPs for this source category. The EPA expects to promulgate a final standard in December 2004.

Pursuant to 40 CFR Part 63, Subpart B, case-by-case MACT determination must be made by the permit applicant for each new unit that has emissions above the major source threshold for HAPs. This document represents the case-by-case MACT determination for the IPP Unit 3 boiler, as required for a new major source of HAPs.

Applicability of Section 112(g) Requirements

The table below presents a summary of projected potential emissions of HAPs emitted from IPP Unit 3. These emission estimates have been derived from HAP constituent analyses of typical western coals, EPA's AP-42 emission factor database, and estimates of levels of control expected based on the configuration of the proposed boiler. One can note that AP-42 factors represent the average of many field tests, and that HAP constituents of coal ash are highly variable.

Annual Emission Estimate of controlled HAPs emissiosn	
HAP[a]	Emissions (TPY)[b]
Metals	
Antimony	0.02
Arsenic	0.18

Beryllium	0.00
Cadmium	0.03
Chromium	0.28
Cobalt	0.03
Hydrogen Chloride	167.01
Hydrogen Fluoride	20
Lead	0.79
Manganese	0.15
Mercury	0.024
Nickel	0.13
Organic HAPs	9.05
Selenium	1.02
Total PCDD/PCDF	0.00
Total	198.714

[a] USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000).
[b] Emission calculation details are provided in the NOI, Appendix C

Based on the emission estimates shown in the table above, two HAPs (HCl and HF) will potentially exceed annual emissions of 10 tpy and total HAPs will exceed 25 tpy. For purposes of new source permitting, IPP Unit 3 is being treated as a major source for HAPs, and will employ case-by-case MACT for these pollutants.

Case-by-Case MACT Analysis

Case-by-Case MACT for Non-Mercury HAP Metals

The PM emitted from IPP Unit 3 will include entrained metals that are contained in coal. These metals will include antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

As noted in the BACT analysis for PM presented in the BACT section, the top control option is a fabric filter baghouse. The control options for non-mercury HAP metals are those identified in the BACT analysis for PM, and the control efficiencies for non-mercury HAP metals correspond to the control efficiencies for PM. Thus, it is concluded that a fabric filter baghouse represents case-by-case MACT for non-mercury HAP metals.

As was also noted in the BACT analysis, the proposed BACT emission limit of 0.020 lb PM per MMBtu heat input (0.015 lb/MMBtu for PM_{10}) is the most stringent limit identified for any PC-fired boiler of any type. Based on precedent established by EPA in establishing MACT standards for several categories of sources emitting non-mercury HAP metals, a PM emission limit is an effective surrogate for individual HAP metals emission limits and is an acceptable format for expressing the MACT standard. For example, EPA described its rationale for setting PM emission limits in the proposed iron and steel MACT standard:

"For the proposed rule, we decided that it is not practical to establish individual standards for each specific type of metallic HAP that could be present in the various processes (e.g., separate standards for manganese emissions, separate standards for lead emissions, and so forth for each of the metals listed as HAP and potentially could be present). When released, each of the metallic HAP compounds behaves as PM. As a result, strong correlation exists between air emissions of PM and emissions of the individual metallic HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions. Therefore, we decided to establish standards for total PM as a surrogate pollutant for the individual types of metallic HAP. In addition, establishing separate standards for each individual type of metallic HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach based on total PM." (66 FR 36835, published July 13, 2001)

For the above reasons, and in light of the precedent established by EPA in setting MACT standards using a surrogate pollutant, it is determined that the BACT emission limit for PM will suffice as MACT standards for non-mercury HAP metals for IPP Unit 3.

Case-by-Case MACT for Acid Gas HAPs

Fluoride emissions from PC-fired boilers result from trace concentrations of fluoride-containing compounds in the fuel. These emissions occur primarily in the form of HF. In addition, HCl emissions will occur as a result of chloride-containing compounds present in the fuel. Both HF and HCl are HAPs subject to the case-by-case MACT requirement.

The control options and relative control effectiveness hierarchy is the same for HCl and HF. The top control option for these acid gases is same as that for SO_2. A wet limestone scrubber in conjunction with a fabric filter baghouse is considered the top control technology for these acid gases. Thus, it is concluded that this control equipment configuration at 90 percent acid gas control represents case-by-case MACT for HF and HCl.

Case-by-Case MACT for Organic HAPs including Dioxin/Furans

The emissions of the organic compounds depend on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas. Organic emissions include volatile, semi-volatile, and condensable organic compounds either present in the coal or formed as a PIC. Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called poly aromatic hydrocarbons (PAH). POM is more prevalent in the emissions from coal combustion because of the more complex chemical structure of coal.

While trace quantities of organic PIC HAPs will be emitted, these are well controlled by implementation of BACT for CO/VOC and PM/PM_{10}, which also represent case-by-case MACT for these HAP species.

Emissions of PCDD/PCDF also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450?F to 650?F.

The formation of dioxin in a combustion source is dependent on the presence of chlorine and complex unburned hydrocarbon chains that may recombine within a certain temperature window of the process as the gases cool. For example, polychlorinated biphenyls (PCB) incinerators have been identified with high dioxin emission levels due to the extreme resistance to complete thermal destruction of this “engineered” complex hydrocarbon molecule and the presence of substantial chlorine. Coal combustion, on the other hand, is a process designed to completely burn organic hydrocarbons at high temperature and ample excess O_2 in the presence of only trace amounts of chlorine. Note that the western coals to be burned in IPP Unit 3 contain very low levels of chlorine, which will limit formation of any chlorine compounds to a fraction of EPA’s published generic AP 42 factors for coal combustion. Further, what chlorine is emitted will be effectively captured by the proposed wet limestone scrubber acid gas control system, and any dioxin that does form will be captured within unburned carbon, expressed as loss on ignition (LOI), and other adsorbents deposited on the filter cake of the baghouse.

Activated carbon injection (ACI) has been shown to be effective at controlling high dioxin emissions from incinerators that burn highly chlorinated waste. In this case, the dioxin emission level is simply too low to be effectively captured by the inherent adsorbents in the baghouse filters. The trace levels of chlorine in the IPP Unit 3 coal and flue gas, combined with the LOI associated with combustion of western coals, yields an effective carbon adsorption mechanism for the trace levels of dioxin which might be emitted from IPP Unit 3. There is no evidence that any additional or measurable dioxin control could actually be achieved by the injection of additional carbon in the proposed unit.

The premise that ACI would result in measurable dioxin control beyond levels achieved by the best controlled similar source is entirely speculative. Good combustion controls and adsorption onto western coal ash and LOI in a fabric filter represents case-by-case MACT for control of dioxin and organics from the proposed IPP Unit 3.

Case-by-Case MACT for Mercury

EPA has specifically targeted mercury for new MACT standards, and has determined that mercury is the HAP of primary concern from PC-fired utility boilers. The EPA-proposed rule was published in Federal Register on Friday January 30, 2004 National Emissions Standards for Hazardous Air Pollutants; and as an alternative, proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units. The control level approved as case-by-case MACT in this application will be revised in the future as required, in the EPA's promulgated MACT rule. The starting point of this case-by-case MACT demonstration is to establish the lowest mercury emission rate that has been achieved in operating PC-fired boilers on western bituminous coal, and then adjusting that value to the coal-specific mercury content of the coal burned at IPP Unit 3. This represents the minimum level of mercury control that would qualify as case-by-case MACT, "the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source".

The analysis also requires consideration of alternative levels of control which go beyond that of the best controlled similar source, i.e., "which reflects the maximum degree of reduction in emissions that the permitting authority, taking into account the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the [proposed] source." These MACT emission levels are considered in the following sections.

Mercury Emissions. Mercury is a naturally occurring constituent of soil and mineral deposits, including deposits of coal. When coal is burned, any trace quantities of mercury present is vaporized at the high temperatures within the furnace section of the boiler. In the presence of chlorine, a portion of the gaseous mercury may react to form mercuric chloride ($HgCl_2$), with most of the remaining mercury emitted as a gas in elemental form. The speciation of the emitted mercury depends on the coal composition (primarily the ash and chlorine content), the combustion system, and the temperature of the flue gas. At the temperatures within the boiler and air pollution control train, a portion of these gaseous mercury species will be emitted to the atmosphere.
Testing performed at IPP Unit 2 indicates that high removal of mercury is achieved in the wet limestone scrubbing system. Up to 90 percent removal efficiency was measured during the tests conducted at this facility while burning Utah bituminous coal.

The other primary variable affecting mercury emissions is the quantity of mercury contained in the particular coal being burned. Western coals exhibit generally lower mercury content than eastern coals. The mercury content of bituminous coal proposed for IPP Unit 3 boiler ranges from as low as 0.02 parts per million (ppm) dry to 0.15 ppm. Establishment of a MACT emission rate for mercury must take this variability into account in order to ensure that MACT will be achieved regardless of coal properties over the life of the units.

Mercury Control Levels and Alternatives. The case-by-case MACT determination for IPP Unit 3 boiler contained in this application focuses on the application of the best level of mercury control being achieved in practice by similar utility scale PC-fired boilers burning western bituminous coals. Then an evaluation was done of the practical potential for achieving even greater levels of control using available technology.

The application for MACT must demonstrate how the project will obtain a degree of emission reduction that is at least as stringent as the emissions reduction that would have been obtained had EPA promulgated MACT standards for mercury control for this source category. As noted above, EPA has published a proposed MACT standard for the source category of PC-fired steam electric generating units, and plans to publish final rules by the end of 2004.

Very limited mercury emission rate data is available for PC-fired boilers in general. EPA has gathered test data from a number of various PC-fired utility boilers for mercury, particularly within the last few years. This "snapshot" sampling was conducted on PC-fired utility boilers ranging from smaller to larger, new to archaic, wall- and tangential-fired, with various coal types and properties, and various combinations of air pollutant control equipment. Even within apparently similar units, the data are highly variable, and this variability is not yet fully understood. Because of the many variables that make each tested unit somewhat unique, and unexplained variability within the data itself, it is difficult at this time to determine a precise emission factor and degree of control that would apply to the proposed units. For example, for boilers burning western coals, available data did not identify a clear advantage one way or the other for units that employed wet scrubbers and ESPs versus units that employed spray dryers and fabric filters.

Although many pilot-scale tests have been performed and a few demonstration projects are scheduled for alternative approaches to mercury control, existing coal plants use either spray dryer/fabric filter, ESP, or ESP/wet FGD systems. FGD systems may control mercury chloride and oxide forms to 85 to 95 percent but are not effective in treating elemental mercury. Conversely, elemental mercury can be adsorbed onto carbon and ash particles, particularly on units that employ fabric filters. This is a technique that has been employed for mercury control in certain incineration processes. Since mercury is emitted from the combustion of western bituminous coals primarily in the form of elemental mercury (due to its lower chlorine content), adsorption with fabric filters should provide the maximum level of control for these particular units. EPA has determined that bituminous fly ash adsorbs elemental mercury very effectively, even if it has little unburned carbon, particularly in combination with fabric filters. Western coals tend to also exhibit higher LOI which builds up on the surface of the filter bags. This is the same postulated adsorption mechanism that has been used successfully on municipal waste incinerators by injecting carbon into the flue gas.

There are three basic forms of mercury in the flue gas from coal combustion: elemental mercury (Hg°), ionic mercury [Hg(II)], and particulate-bound mercury [Hg(p)]. Both Hg° and Hg(II) are in a vapor phase at flue gas cleaning temperatures. Hg° is insoluble in water and cannot be captured in wet scrubbers. The predominate Hg(II) compounds in coal flue gas are weakly to strongly soluble and can be generally captured in wet FGD scrubbers. Both Hg° and Hg(II) can be adsorbed onto porous solids such as fly ash, activated carbon, or calcium-based acid gas sorbents for subsequent collection in a PM control device. Hg(II) is easier to adsorb than Hg°. Hg(p) is entrained in solids that can be readily captured in ESP's and fabric filter baghouses. Mercury is found predominantly in vapor phase in the boiler flue gas. If this vapor phase mercury is condensed onto PM, the PM can be easily removed with the baghouse. Cooler temperatures of flue gases significantly improve mercury removal efficiency. The flue gas exiting the boiler and air pre-heater has a temperature in the range of 280?F to 300°F.

Information Collection Request (ICR) Mercury Data

The EPA issued an Information Collection Request (ICR) under the authority of Section 114 of the Clean Air Act (CAA) to all coal–fired electric utility steam generating units requesting mercury in coal trace analysis data. In addition, 80 of these units were selected to represent a cross section of boiler and control device types and were required to conduct stack tests to evaluate their mercury emissions.

Data from the ICR study were reviewed to identify the best-controlled similar source for mercury emissions. This data was sorted first by boiler type and fuel type to eliminate facilities that were not similar to the proposed IPP Unit 3. Only 25 facilities that utilized conventional PC-fired boilers and burned bituminous coal were considered for MACT analysis. Facilities that indicated negative mercury removal efficiencies were assumed to have zero percent control efficiency. Data was further ranked by average control device efficiency. The table below provides the minimum, maximum, and average control efficiencies of various control technologies arranged by the average degree of emission reduction of mercury for each type of control device.

Control Efficiencies of Air Pollution Control Devices for Mercury Sorted by the Type of Control Device[a]

PM Control	SO_2 Control	No. of Units in the database	Minimum Control Efficiency %	Maximum Control Efficiency %	Average Control Efficiency %
Particulate Scrubber	None	1	12	12	12.00
Hot Side Electrostatic Precipitator	None	2	0	30.41	15.21
Hot Side Electrostatic Precipitator	Compliance Coal	1	18.73	18.73	18.73
Cold Side Electrostatic Precipitator	None	3	4.95	35.72	23.30
Cold Side Electrostatic Precipitator	Sorbent Injection	1	44.89	44.89	44.89
Cold Side Electrostatic Precipitator	Compliance Coal	4	25.19	89.88	48.68
Hot Side Electrostatic Precipitator	Wet Lime/Limestone Scrubber	3	20.95	75.75	56.65
Cold Side Electrostatic Precipitator	Wet Lime/Limestone Scrubber	3	44.89	68.61	60.67
Baghouse	Wet Lime/Limestone Scrubber	2	74.53	76.33	75.43
Baghouse	Compliance Coal	1	86.52	86.52	86.52
Baghouse	None	1	92.51	92.51	92.51
Baghouse	Lime Spray Dryer Absorber	3	97.36	98.81	98.09

Note:
[a] All data downloaded from www.epa.gov/ttn/atw/combust/utiltox/icrdata.xls dated January 2002.

Based on ICR study data, the following four technologies have been identified as possible control technologies that can be applied to the proposed IPP Unit 3 for achieving case-by-case MACT requirements contained in 40 CFR 63.41.

1. Baghouse with wet lime or limestone scrubber
2. Baghouse with compliance coal
3. Baghouse with no SO_2 control
4. Baghouse with lime spray dryer absorber

Since SO_2 control is required by the New Source Performance Standards and the Prevention of Significant Deterioration program, no further consideration was given to No. 2 and 3 technology options listed above.

The remaining two technologies, baghouse with wet lime or limestone scrubber and baghouse with lime spray dryer absorber were further analyzed for achieving the maximum degree of emission reduction with consideration of costs, non-air quality health, and environmental impacts and energy requirements. The wet scrubber technology was considered as MACT for the IPP Unit 3 boiler application because it not only provides a high level of emission reduction for mercury but also provides a higher level of emission reduction for SO_2, sulfur related compounds TRS and RSC, HCl and HF than the baghouse with dry lime spray dryer adsorber technology.

In September 1999, GE –Energy and Environmental Research Corporation conducted speciated mercury testing at IPP Unit 2. Unit 2 employs a baghouse and wet limestone scrubber for air pollution control similar to those proposed for Unit 3. Unit 2 burns bituminous and sub-bituminous Utah coal. Coal planned for Unit 3 will be of similar composition. The test results showed an overall removal efficiency of 77.65 percent for mercury. Test results from this mercury testing are shown in the table below.

Summary of Mercury Stack Test Results for IPP Unit 2[a]

Mercury Species	Wet Scrubber Inlet Emission Rate (lb/hr)	Wet Scrubber Outlet Concentration (lb/hr)	Scrubber Removal Efficiency %	Overall Mercury Removal Efficiency %[b]
Particle Bound Mercury	1.30E-04	6.70E-05		
Oxidized Mercury	7.80E-03	4.40E-04		
Elemental Mercury	1.40E-03	2.50E-03		
Total Mercury	9.40E-03	3.00E-03	68.09	77.65

[a] Mercury Emissions and Speciation Testing at Intermountain Power Plant Unit 2 SGA Test Report, January 5, 2000.
[b] Overall mercury removal efficiency calculated based on mercury concentration of 0.02 ppm (d) in the coal and a coal feed rate of 67,100 lb/hr.

A fabric filter combined with the use of the wet limestone scrubber was determined to represent the best technology for control of mercury from the combustion of bituminous western coal from existing utility scale PC-fired boilers. This is the control technology proposed for IPP Unit 3. Because the flue gas exiting the boiler and air preheater has a temperature in the range of 280?F to 300°F, additional cooling such as water spraying would be required prior to carbon injection for effective removal of mercury in the baghouse. This carbon injection was not considered for this facility as testing at Unit 2 has shown high mercury removal efficiency using a baghouse and wet limestone scrubber.

40 CFR 63.40 defines the MACT emission limitation for new sources as the emission limitation which is not less stringent that the emission limitation achieved by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed and reconstructed source. This MACT emission limitation can be calculated based on uncontrolled emission level for an emission unit and maximum achievable control efficiency identified in previous section. The uncontrolled annual emissions for the proposed IPP Unit 3 are 0.42 tpy based on the ICR test data and coal trace analysis data. The maximum achievable control efficiency is 77.65 percent based on the proposed baghouse and wet lime scrubber design. This results in an estimated controlled mercury emission rate of 0.0215 lb/hr, 2.37 lb/10^{12}Btu heat input, or 0.09 tons per year.

Comparison to Previously Issued Similar Source Permits

IPP has identified eight coal-fired power plant permits that have been issued after December 14, 2000 and that were evaluated for case-by-case MACT requirements in the permits pursuant to Section 112(g). The controlled mercury emission rate expectedfor IPP Unit 3 is lower than these other reported mercury emission rates. The table below provides a comparison of other permit mercury emission rates with the rate proposed for IPP Unit 3 boiler.

Table 6-11		
Comparison of Mercury Emission Rates Established in Previously Issued Permits		
Plant Name and Location	Size	Emission Rate
Tucson Electric Power Springerville, Unit 3 and 4 Arizona	450 MW each	6.9 lb/10^{12}Btu
Holcomb Unit 2 Kansas	660 MW	Considered minor source of HAPs. No emission limit established in the permit. Emission limit to be established after testing
Thoroughbred Units 1 and 2 Kentucky	750 MW each	3.86 lb/10^{12}Btu
Wygen Unit 2 Wyoming	500 MW	12.6 lb/10^{12}Btu
Plum Point Units 1 and 2 Arkansas	550 – 800 MW each	12.8 lb/10^{12}Btu
Bull Mountain Roundup Unit 1 Montana	780 MW	2.69 lb/TBtu

Table 6-11		
Comparison of Mercury Emission Rates Established in Previously Issued Permits		
Plant Name and Location	Size	Emission Rate
Rocky Mountain Power Hardin Unit 1 Montana	113 MW	Considered minor source of HAPs. No emission limit established in the permit.

The only facility with a lower proposed mercury emission rate or higher mercury removal efficiency is the permit issued for MidAmerican CBEC Unit 4 in Council Bluffs, Iowa. The MidAmerican permit analysis estimated that the proposed lime spray dryer and fabric filter would remove 35% of the uncontrolled mercury from the coal. The Iowa Department of Natural Resources established a permit limit that was based on 80% mercury removal with the addition of an activated carbon injection system.

The IPP Mercury MACT analysis differs from the analysis conducted for MidAmerican in several key areas. MidAmerican Unit 4 is designed to burn PRB subbituminous coal. IPP Unit 3 will burn western bituminous coals. Based on the ICR database, subbituminous coals with lime spray dryer/fabric filter, as proposed at MidAmerican, 35% mercury control is achievable. The IPP design with western bituminous coal and fabric filter/wet limestone FGD will result in 77.65% mercury control (as demonstrated during IPP stack testing). The MidAmerican project is to start construction this month. Because the start of construction was before the issuance of the proposed federal MACT standards for utility coal-fired boilers, IDNR was uncomfortable with deferring a MACT determination. IPP will not start construction of Unit 3 until after the MACT standards are proposed.

Kansas City Power and Light, Hawthorne Unit 5, Missouri

At the time this PSD permit was issued (8/17/1999), a Case by Case MACT determination was not required per 40 CFR Part 63. The facility is major for HAPs. The applicant's only requirement was to submit estimated HAP emissions. The estimated net emissions increase of Mercury emissions was 0.05 tons/year.

Tucson Electric Power, Springerville Units 3 and 4, Arizona

The State of Arizona Department of Environmental Quality (ADEQ) performed a MACT analysis for this application during the permit review process. ADEQ set a mercury lb/MMBtu limit based on the range of mercury in the design coals for Units 3 and 4 and the mercury removal efficiency demonstrated across the lime spray dryers and baghouses on the existing Units 1 and 2. Units 3 and 4 will utilize similar controls. The permit has the following conditions related to Mercury.

III.A Unit 3 and Unit 4 Emission Limits and Standards

Condition 10 Mercury Emission Standard

a. The Permittee shall not cause to be discharged into the atmosphere from the stack of Unit 3 and Unit 4 any gases which contain mercury in excess of 0.0000069 lb per million Btu heat input derived from the combustion of fuel. Compliance with this emission limit shall be determined using a three hour averaging period.

b. The mercury emission standard in Specific Condition III.A.10.a above shall apply at all times except during periods of startup, shutdown or malfunction.

III.D Unit 3 and Unit 4 Testing Requirements

Condition 10 Mercury

a. The Permittee shall perform initial and annual performance tests on Unit 3 and Unit 4 to determine compliance with the mercury emission limitation in Specific Condition III.A.10.a of Attachment "B".

b. Each performance test for mercury shall be performed using EPA Reference Method 29.

c. The Permittee shall develop and submit to the Director a site-specific test plan in accordance with the provisions of 40 CFR 63.7(c) at least 60 days prior to each scheduled performance test required by Specific Condition III.D.10.a above.

Sand Sage Power, LLC, Holcomb Unit 2, Kansas

Sand Sage Power provided information in the permit application to the State of Kansas Department of Health & Environment (KDHE) that the facility was a minor source of HAPs thus a MACT analysis was not required. There is not a mercury emission limitation in the permit. Within 180 days after initial startup of the Holcomb Unit 2 boiler, the permittee wil be required to conduct performance tests to verify that HAP emissions do not exceed 10 tons per year of any individual HAP or 25 tons per year of combined HAPs.

Thoroughbred Generation Company LLC, Thoroughbred Units 1 and 2, Kentucky

Thoroughbred conducted a case by case MACT determination. The State of Kentucky Department for Environmental Protection issued a permit with the following Mercury permit conditions.

Section B Emission Points, Emission Units, Applicable Regulations, and Operating Conditions
Condition 2 Emission Limitations

k. Pursuant to Regulations 401 KAR 51:017, mercury emissions shall not exceed 0.00000321 lb/MMBtu from each unit based on a quarterly average.

m. Pursuant to 40 CFR 63.43(d) case-by-case MACT determination, each pulverized coal fired steam electric generating unit, shall not exceed the following hazardous air pollutants (HAP) emission limitations listed below:

Mercury 0.1047 tons/year per unit

Condition 3 Testing Requirements

e. Case-by-Case MACT Requirements
Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, the permittee shall demonstrate compliance with the applicable emissions limitations for the following HAPs in the table below:

Mercury Method 29

f. Pursuant to 40 CFR 63.43(g)(2)(ii) case-by-case MACT determination, the permittee shall demonstrate compliance with these emission limitations within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial startup of these emission units.

g. Pursuant to Regulation 401 KAR 52:020, Section 10, during the initial compliance test, the permittee shall take a sample of the fuel "as fired" and analyze it to determine the HAP content in the fuel. This information shall be used to establish a correlation between the sample's HAP content and HAP emissions for monitoring purposes. The permittee shall demonstrate compliance with these emissions limits annually to validate the correlation between grab samples HAP content and HAP emissions.

Black Hills Corporation, Wygen Unit 2, Wyoming

Black Hills conducted a case by case MACT determination. The State of Wyoming Department for Environmental Quality (WDEQ) determined that the proposed air pollution controls (Low NO_x burners, SCR, Lime Spray Dryers and Baghouses) were MACT for mercury and other HAPs. WDEQ did not place a permit limitation on mercury but estimated emissions were 0.0000122 lb/MMbtu or 0.275 tons per year. The following condition related to mercury is in the WDEQ issued permit.

Condition 10 The following testing shall be performed and a written report of the results submitted within 90 days after initial start-up:

D. PC Boiler exhaust shall be tested prior to control devices and at the PC Boiler Stack to determine emissions of metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, mercury, nickel and selenium) and control efficiencies using EPA Method 29 or equivalent methods. Results of the tests shall be reported in the units of lb/hr and control efficiencies.

Roundup Power, Roundup Unit 1, Montana

The State of Montana Department of Environmental Quality (MDEQ) deferred the MACT determination until after the construction permit was issued. Therefore there are no emission limitations or conditions related to Mercury in the permit. It is felt that they will wait until the Federal MACT standards are proposed for coal-fired units.

Plum Point Energy Associates, LLC, Plum Point Unit 1, Arkansas

The final permit was issued by the Arkansas Department of Environmental Quality (ADEQ) on August 20, 2003. ADEQ determined that the MACT standard for Mercury will be to control emissions to 12.8 lb/trillion Btu using a SCR/dry scrubber/fabric filter control equipment combination. The controls are estimated to remove 34.2% of the uncontrolled mercury emissions. There are no specific testing or compliance demonstration conditions in the permit.

Rocky Mountain Power, Hardin Unit 1, Montana

Rocky Mountain Power provided information in the permit application to the State of Montana Department of Environmental Quality (MDEQ) that the facility was a minor source of HAPs thus a MACT analysis was not required. There is not a mercury emission limitation in the permit.

MidAmerican Energy, Council Bluffs Energy Center Unit 4, Iowa

MidAmerican Energy submitted a MACT analysis as part of the permit application. The facility is major for HAPs. The State of Iowa Department of Natural Resources (IDNR) determined that MACT was 80% mercury removal of the uncontrolled mercury emissions with the addition of activated carbon injection. The lime spray dryer and baghouse account for approximately 35% mercury removal with the remaining 45% (of the 80%) from the activated carbon injection system. The mercury emission limit is based on the uncontrolled mercury emission rate (worst case design coal) times the 80% removal efficiency. The specific conditions related to mercury in the permit are as follows:

Condition 10b	112 Emission Limits
Mercury	17×10^{-6} lb/MMBtu, average of three test runs
Condition 14	Operating Limits

I. The minimum activated carbon feed rate shall be 10 pounds per million cubic feet of exhaust gas or a rate specified for one of the trials of the optimization study required under condition M of this section. Deviation from the minimum 10 pounds per million cubic feet of exhaust gas shall only occur for the duration of a given trial. At the end of each trial, the injection rate must be returned to a minimum of 10 pounds per million cubic feet.

M. Optimization studies are required for the control of SO_2, NO_x and Hg. These studies shall evaluate the affects of increased activated carbon injection, increased injection of slurry in the spray dryer absorber, and the optimization of the operation of the SCR unit.

P. A compliance test for mercury must be conducted once annually.
- (1) Stack test must be performed according to method outlined in section 12 of this permit.
- (2) A test report must be submitted to the Department according to the schedule outlined in Section 8 of this permit.
- (3) Testing must be completed once every calendar year with a minimum of nine months between each test.

Condition 15 Operating Condition Monitoring

- M. The following information must be kept concerning the activated carbon injection system.
- (1) A continuous record of the activated carbon feed rate in pounds per million cubic feet of exhaust gas.
- (2) A copy of the approved optimization protocol.
- (3) A record of the time each trial of the optimization study begins and ends and enough information to identify which trial is being undertaken during that period.
- P. A copy of the final test results for each compliance test for mercury shall be maintained.

Required Data for 40 CFR 63.43

The content of an application for a case-by-case MACT determination is described in 40 CFR 63.43. The following sections correspond to the case-by-case MACT application content prescribed in 40 CFR 63.53 (e).

The name and address (physical location) of the major source to be constructed or reconstructed: IPP Unit 3 is proposed to be located on the existing IPP site in Millard County, Utah. The project is a major source of HAPs (i.e., greater than 10 tpy of HCl and HF and greater than 25 tpy of total HAPs), as shown in the Annual Emission Table.

A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included: The IPP Unit 3 Project consists of one nominal 950-gross MW, PC-fired, utility steam-electric generating unit. The applicable source category is "utility steam-electric generating units". The PC-fired boiler is the source requiring new source MACT. The boiler is to be equipped with a limestone wet scrubber for acid gas control and fabric filters for PM and PM_{10} control.

The expected date of commencement of construction: Construction of IPP Unit 3 is expected to commence 2004.

The expected date of completion of construction: Construction is expected to be completed in 2008.

The anticipated date of startup of operation: Startup of the Unit 3 is anticipated in 2008.

The HAP emitted by the constructed major source, and the estimated emission rate for each such HAP: The HAPs projected to be emitted annually from the Unit 3 PC-fired boiler are summarized in the Annual Emission Table. These values are estimates based on EPA AP-42 emission factors, the EPRI Coal HAP report, Sargent & Lundy's (owner's engineer for this project) engineering estimates, and properties of the proposed coal to be fired and maximum rated heat input. Additional details on emissions are provided in the three tables below for trace metals, organic chemicals, and for acid gases.

Emissions of Trace Metals

Pollutant[a]	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)	Uncontrolled[e] Emissions (lb/hr)	Uncontrolled[e] Emissions (tpy)
Antimony[b]	0.01	0.02	2.23	9.75
Arsenic[b]	0.04	0.18	17.46	76.47
Beryllium[b]	0.00	0.00	0.17	0.75
Cadmium[b]	0.01	0.03	3.40	14.91
Chromium[b]	0.06	0.28	27.93	122.33
Cobalt[b]	0.01	0.03	3.24	14.20

Lead[b]	0.181	0.79	11.33	49.63
Manganese[b]	0.03	0.15	15.17	66.47
Mercury[c]	0.02	0.09	0.09	0.42
Nickel[b]	0.03	0.13	12.85	56.29
Selenium[d]	0.23	1.02	1.94	8.50

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)
[b]AP-42 Section 1.1, Table 1.1-18, (9/1998)
[c]Engineering calculations based on mercury stack test conducted at IPP Units 1 and 2
[d]Engineering calculations based on EPRI Coal HAP report
[e]Uncontrolled emissions for all metals except mercury and selenium were calculated based on a control efficiency of 99.8 percent. Mercury control was estimated based on coal analysis and stack testing. Selenium control was based on the EPRI Coal HAP report

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Emissions of Organic Compounds

Pollutant[a]	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Acenaphthene[b]	0.00	0.00
Acenaphthylene[b]	0.00	0.00
Acetaldehyde[b]	0.23	1.01
Acetophenone[b]	0.01	0.03
Acrolein[b]	0.12	0.51
Anthracene[b]	0.00	0.00
Benzene[c]	0.03	0.15
Benzo(a)anthracene[b]	0.00	0.00
Benzo(a)pyrene[b]	0.00	0.00
Benzo(b,j,k)fluoranthene[b]	0.00	0.00
Benzo(g,h,i)perylene[b]	0.00	0.00
Benzyl chloride[b]	0.28	1.24
Biphenyl[b] Bis(2-ethylhexyl)phthalate (DEHP)[b]	0.00 0.03	0.00 0.13
Bromoform[b]	0.02	0.07
Carbon disulfide[b]	0.05	0.23
2-Chloroacetophenone[b]	0.00	0.01
Chlorobenzene[b]	0.01	0.04
Chloroform[b]	0.02	0.10
Chrysene[b]	0.00	0.00
Cumene[b]	0.00	0.01
2,4-Dinitrotoluene[b]	0.00	0.00
Dimethyl sulfate[b]	0.02	0.08

Ethyl benzene[b]	0.04	0.17
Ethyl chloride[b]	0.02	0.07
Ethylene dichloride[b]	0.02	0.07
Ethylene dibromide[b]	0.00	0.00
Fluoranthene[b]	0.00	0.00
Fluorene[b]	0.00	0.00
Formaldehyde[c]	0.03	0.12
Hexane[b]	0.03	0.12
Indeno(1,2,3-cd)pyrene[b]	0.00	0.00
Isophorone[b]	0.23	1.03
Methyl bromide[b]	0.06	0.28
Methyl chloride[b]	0.21	0.94
5-Methyl chrysene[b]	0.00	0.00
Methyl ethyl ketone[b]	0.16	0.69
Methyl hydrazine[b]	0.07	0.30
Methyl methacrylate[b]	0.01	0.04
Methyl tert butyl ether[b]	0.01	0.06
Methylene chloride[b]	0.12	0.51
Naphthalene[b]	0.01	0.02
Phenanthrene[b]	0.00	0.00
Phenol[b]	0.01	0.03
Propionaldehyde[b]	0.15	0.67
Pyrene[b]	0.00	0.00
Tetrachloroethylene[b]	0.02	0.08
Toluene[c]	0.01	0.06
1,1,1-Trichloroethane[b]	0.01	0.04
Styrene[b]	0.01	0.04
Xylenes[b]	0.01	0.07
Vinyl acetate[b]	0.00	0.01
Total PCDD/PCDF[c]	0.00	0.00

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)
[b]AP-42 Section 1.1, Table 1.1-13 and Table 1.1-14 (9/1998)
[c]Emission calculations based on EPRI Coal HAP Report

Emissions of Acid Gases				
Pollutant[a]	Controlled[b] Emissions (lb/hr)	Controlled[b] Emissions (tpy)	Uncontrolled[b] Emissions (lb/hr)	Uncontrolled[c] Emissions (tpy)
Hydrogen Chloride	38.13	167.01	381.31	1670.14

Hydrogen Fluoride	4.7	20	46.85	200.00

[a]USEPA - TTN, Unified Air Toxics website, Section 112 HAPs, (8/21/2000)
[b]Engineering calculations based on Sargent and Lundy's engineering estimates for uncontrolled and controlled acid gas emissions
[c]Uncontrolled emissions were calculated based on a control efficiency of 90 percent.

Any federally enforceable emission limitations applicable to the constructed or reconstructed major source: Federally enforceable emission limits will be established in the PSD permit as BACT requirements. In addition, 40 CFR 60 Subpart Da and 40 CFR 72-75 are also applicable requirements for the proposed IPP Unit 3.

The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source: The expected capacity factor of the boiler is expected to be higher than 90 percent. The HAP emission rates provided in the three tables above (Emissions of Trace Metals, Emissions of Organic Compounds, and Emissions of Acid Gases) are based on a capacity factor of 100 percent for the unit taking into account the use of all add on controls. However, combustion controls that are inherent to the boiler have been excluded for the calculation of uncontrolled emissions.

The controlled emissions for the constructed or reconstructed major source in tpy at expected and maximum utilization capacity: The controlled emissions of HAPs are provided in the tables: Emissions of Trace Metals, Emissions of Organic Compounds, and Emissions of Acid Gases). These emissions are also calculated based on 100-percent capacity factor but taking into account all proposed air pollution control devices.

A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section: The table below provides recommended emission limits and test method for each HAP or category of HAP.

Proposed Emission Limits

HAP Category	Surrogate Pollutant	Emission Limit	Test Method
Organics	CO	0.150 lb/MMBtu	Reference Method 10
Acid Gases	SO_2	0.10 lb/MMBtu	CEM for SO_2
Trace Metals	PM	0.020 lb/MMBtu	Reference Method 5
Mercury	SO_2, PM	Same as above	Same as above

The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, etc.: MACT for HAPs from IPP Unit 3 boiler burning western bituminous coal and blend of bituminous and subbituminous coals is concluded to be control technology capable of demonstrating BACT for CO, VOC, PM, PM_{10}, and SO_2. Technical information on the design of the proposed control technology is provided in the PSD application in the BACT sections of this review.

Supporting documentation including identification of alternative control technologies considered, and analysis of cost of non-air quality health environmental impacts or energy requirements for the selected control technology: The project is required to meet BACT for CO and VOC as well as PM and PM_{10}. This combination of technology also represents the most stringent control that has been demonstrated in practice for mercury control from similar PC-fired utility boilers burning western bituminous coal and blend of bituminous and subbituminous coals; less effective control technologies would not satisfy BACT requirements, and hence no alternatives analysis is required.

Any other relevant information required pursuant to subpart A: No other relevant information has been identified.

MACT Compliance

Since a fabric filter has been determined to be MACT for trace metals from the combustion of bituminous coal and blend of bituminous and subbituminous coals; for IPP Unit 3, compliance will be by demonstrating proper operation of the fabric filter. A detailed CAM plan has been proposed to ensure continuous compliance with the PM and PM_{10} emission limits. Adherence to this CAM plan will similarly ensure that the fabric filters are performing at design efficiency for control of HAP metals, including mercury.

Compliance with MACT for organic HAPs will be based on good combustion practices and initial and while compliance with acid gases HAPs will be based on proper operation and maintenance of the SO_2 scrubbing system.

January 30, 2004, US EPA published in Federal Register/Vol. 69. No 20 (4652 – 4752): "Proposed National Emission Standards for Hazardous Air Pollutants; and in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule."

Based on the the fact that EPA this proposed rule UDAQ will set in this project Intent to Approve (ITA) a Condition #12 with Hg limit of 6.0×10^{-6} lb/MWr - the emission limits for coal-fired electric utility steam generating units using bituminous coal.

Upon final promulgation of National Emission Standards for Hazardous Air Pollutants; and in Alternative Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units Rule, compliance with those standards shall apply in lieu of compliance with requirements set in the ITA Condition #12.

Different Combustion Processes Evaluation

Evaluation of PC, Intergrated Gasification Combined Cycle (IGCC) and Circulating Fluidized Bed (CFB) Combustion

As a part of the IPSC NOI general process description, and in the supplemental (November 26, 2003) submitted report on Circulating Fluidized Bed (CFB) coal combustion, Integrated Gasification Combined Cycle (IGCC) technology and Unit 3, IPSC included some of the important design criteria used in selecting the PC boiler for the Unit 3 and they are as follows:

?Unit 3 should be capable of generating 900–MW net output.
?Unit 3 would be a base load unit, and therefore the unit must be designed with combustion process technologies capable of achieving a capacity factor of at least 90 percent.

?As base line unit, Unit 3 must be designed to have a very low forced outage rate. Therefore, Unit 3 must be designed with highly reliable boiler and turbine, reliable emission control technologies, and reliable ancillary equipment.

?Based on projected fuel availability, Unit 3 boiler should be designed to fire Utah bituminous coal with an average maximum design coal sulfur content of 0.75 %, and design coal heating value of 11,193 Btu/lb.

To insure flexibility in the fuel supply, the proposed boiler should be capable of burning a blend of Utah bituminous and western sub-bituminous coal.

For safety considerations, operator training considerations, and O&M reliability, the boiler should be (to the extent practicable) compatible with the existing IPP coal-fired units.

?Unit 3 must be equipped with the best available emissions control technologies, and emissions from the proposed unit must not cause or contribute to a violation of the applicable NAAQS or applicable PSD increment.

Based on their analysis IPSC concluded that:

?PC is the only coal-fired generating combustion process technology that can reliably meet the design criteria established for the proposed unit;

?IGCC and CFB are not feasible power generating generation options for the proposed Unit 3, as proposed;

?the BACT process should be used to identify the best emissions control technologies available for the source as defined by the applicant, and should not be used to define or re-define the source (IPSC was unable to find any example of a regulating agency redefining a proposed PC boiler project with an IGCC, as a result of BACT determination); nevertheless, IPSC submitted a comparative evaluation of PC, CFB, and IGCC technologies

?emission rates from the proposed PC boiler will be lower than emission rates actually achieved in practice at existing CFB or IGCC facilities, and virtually identical emissions that might be achieved from the next generation CFB and IGCC plant; and

?the economic impact associated with CFB and IGCC technologies are cost prohibitive;

Alternative Electricity Generation Options

Once the design criteria for Unit 3 were established, alternative electricity generating technologies were evaluated. Consideration was given to both CFB and IGCC technologies using a process similar to that used in determining Best Available Control Technology (BACT). Technical and economic variables evaluated during the technical review process included:

?size of existing steam generation equipment;
?heat rate and unit performance;
?availability/reliability;
?demonstrated performance on Utah bituminous coal;
?potential air emissions;
?capital costs;
?operating costs;
?maintenance costs;
?waste products; and
?water usage.

In order to evaluate potential emissions from an IGCC facility, IPSC identified the capacity factors, heat rates, and actual emissions achieved in practice from currently operating IGCC units. The next two tables summarize the annual capacity factors, heat rates, and actual emissions achieved in practice at currently operating IGCC units.

IGCC Actual Capacity Factors and Heat Rates

	Polk Power Station IGCC		Wabash River IGCC	
	Capacity Factor	Net Heat Rate	Capacity Factor	Net Heat Rate
Year	%	Btu/kWh	%	Btu/kWh
1996	11.54	n/a	--	--
1997	45.38	n/a	34.95	11,716
1998	62.37	n/a	52.44	11,341
1999	70.20	9,877	32.88	10,225
2000	77.01	10,378	44.54	8,746
2001	63.46	10,725	36.08	9,244

Data summarized in the table above were obtained from the U.S. EPA's Acid Rain emissions scorecard (http://www.epa.gov/airmarkets/emissions/index.html) and Resource Data International's PowerDat database

Polk Power Station IGCC and Wabash River IGCC Actual Emissions

Polk Power Station IGCC						Wabash River IGCC			
Year	NOx		SO_2			NOx		SO_2	
	lb/ MMBtu	ton/ year	lb/ MMBtu	ton/ year		lb/ MMBtu	ton/ year	lb/ MMBtu	ton/ year
1996	0.15	165	0.135	149					
1997	0.12	453	0.220	935		0.150	515	0.266	1,051
1998	0.10	537	0.224	1,321		0.140	534	0.167	851
1999	0.09	578	0.180	1,183		0.150	359	0.132	461
2000	0.10	586	0.146	918		0.140	387	0.173	657
2001	0.10	504	0.153	818		0.170	307	0.143	449

The next table summarizes the design basis for each identified electricity generating technology identified and considered as an alternative to a PC-fired steam electric plant.

Generating Technologies - Initial Design Basis

	Proposed PC Unit #3	CFB Boiler	IGCC
Gross Output (MW)	950 (1 boiler and 1 steam turbine)	975 (3 boilers and 1 steam turbine)	1014 (4 gas turbines, 4 HRSGs, and 1 steam turbine) Note: the CT's are derated by approximately 16% due to the site elevation of 4646 ft.
Net Output (MW's)	900	900	912
Net Plant Heat Rate (Btu/kW-Hr)	~ 9700	~9,900	~9700 - 9800
Capital costs	Base	Base + $55 x 10^6$	Base + $500 x 10^6$
Anticipated Emission Rates (lb/MMBtu – 30 day average)			
SO_2	0.10	0.10	0.12
NO_X	0.07	0.09	0.09
Particulate (filterable)	0.015	0.015	0.011
Mercury	55- 75% controlled based on ICR database	55- 75% controlled based on ICR database	Unknown, based on DOE report possibly 30%

Technical information for the two operating IGCC facilities was obtained from the following documents:

Wabash River Coal Gasification Repowering Project – Final Technical Report, Prepared by Wabash River Energy Ltd., Work Performed Under Cooperative Agreement DE-FC21-92MC29310 for the U.S. Department of Energy, August 2000 ("Wabash River Final Report").

Wabash River Coal Casification Repowering Project: A DOE Assessment, U.S. Depart of Energy, DOE/NETL-2002/1164, January 2002 ("Wabash River DOE Assessment").

Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project – Final Technical Report, Prepared by Tampa Electric Company, Work Performed Under Cooperative Agreement DE-FC-21-91MC27363, August 2002 ("Polk Final Report").

Additionally, CFB boilers are considered to be better suited to poor quality fuels (such as high sulfur/low heating value coals or coal mine waste) and IGCC process was conceived to take advantage of an inexpensive and abundant fuel source (i.e., coal), blended feed stocks, in an efficient combined cycle plant.

Based on the above provided (and information provided in the complete PC, IGCC and CFB IPSC BACT paper in the Appendix I, dated November 26, 2003) PC dry bottom, tangentially or wall fired boiler for the Unit 3 is the only identified technology for generating electricity using coal at the proposed modification to IPP. Other identified technologies, such as CFB and IGCC, would require a fundamental redefinition of the source, which UDAQ has determined to be outside the scope of the applicable permitting and regulatory requirements.

V. RECOMMENDED APPROVAL ORDER CONDITIONS

General Conditions:

1. This Approval Order (AO) applies to the following company:

Site Location	Corporate Office Location
Intermountain Power Service Corporation	Intermountain Power Service Corporation
850 West Brush Wellman Road	850 W. Brush Wellman Road
Delta, UT 84624-9522	Delta, UT 84624

Phone Number: (435) 864-4414
Fax Number: (435) 864-6670

The equipment listed in this AO shall be operated at the following location:

850 West Brush Wellman Road, Delta, Millard County, Utah

Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS and/or NESHAP and/or MACT standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. Records shall be kept for the following minimum periods:

   A. Used oil consumption — Five years

   B. Emission inventories — Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.

C. All other records Five years

6. Intermountain Power Service Corporation (IPSC) shall install and operate the nominal 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler and modified equipment associated with Unit 3, as defined by this AO, in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on December 16, 2002 and additional information submitted to the DAQ on May 14, 2003, May 27, 2003, July 28, 2003, September 8, 2003, November 6, 2003, November 7, 2003, November 18, 2003, December 12, 2003, December 18, 2003, January 12, 2004, March 24, 2004, and March 29, 2004.

7. The approved installations shall consist of the following equipment or equivalent*:

A. Unit 3 Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports System

Maximum Heat Input Rate:	9050 x 10^6 Btu/hr
Type of Burner:	Ultra Low NO_x Burners or equivalent

B. Unit 3 Stack

Stack Height:	At least 712 feet, as measured from ground level at the base of the stack.

C. Unit 3 Control Equipment

C.1 Main Boiler Stack Fabric Filter Baghouse

Baghouse Filter Material: Ryton or equivalent

C.2 Wet Limestone Flue Gas Desulfurization System built in redundancy

C.3 Selective Catalytic Reduction System with ammonia injection

D. Two Unit 3 Cooling Towers, 3A and 3B, Equipped with mechanical Mist Eliminators

E. Unit 3 Coal Handling

E.1 Modification of Existing Conveyors: Higher capacity motors on Belts 7 and 8, Belts 9A/9B, 15A/15B expanded to 48"wide;
E.2 New Unit 3 36"wide Conveyors-16A/16B, 17A/17/B, en mass chain totally enclosed conveyors 301A/B, 302A/B, 303, 304, 305, and 306.
E.3 New Coal Transfer Building #5 with Dust Collector EP-127.
E.4 New Coal East Storage Silos 301, 302, 303, 304, and Coal East Storage Silo Bay Dust Collector EP-128.
E.5 New Coal West Storage Silos 305, 306, 307, 308 and Coal West Storage Silo Bay Dust Collector EP-129.

F Unit 3 Fly Ash Handling Equipment: To convey Fly Ash from the fabric filter to the storage silo

F.1 Fly Ash Storage Silo 1C with Loading Spout Vent Dust Collector EP-171
F.2 Fly Ash Storage Silo 1C with Vent Dust Collector EP-172

G Unit 3 Bottom Ash Handling System to convey bottom ash from boiler to storage area.

H. Unit 3 Limestone Handling System for WFGD system

I. Unit 3 WFGD Sludge Handling System

J. Existing Auxiliary Boiler Modification
Installation of an extension on each boiler stack so that each stack height is at least 72 feet, as measured from the ground level at the base of the stack.

K. Unit 3 Water Treatment Plant, Steam System, Turbine generator, and Air heaters**

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

8. Intermountain Power Service Corporation shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

9. Except for start-up, shut-down, or malfunction, emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: Unit 3 Main Boiler Stack		
Pollutant	Emission Rate (lb/MMBtu)	Averaging Period

SO_2	0.12	24-hour block average
SO_2	0.10	30-day rolling average
NO_x	0.07	30-day rolling average
H_2SO_4	0.0044	24*-hour block average
PM_{10} (filterable)	0.015	3-test run average
PM (filterable)	0.020	3-test run average
VOC	0.0027	3- test run average
Fluorides/HF	0.0005	3- test run average
Lead	0.00002	3- test run average

Source: Unit 3 Main Boiler Stack		
Pollutant	Emission Rate (lb/hr)	Averaging Period
PM_{10} (filt.+condensable)	221	24*-hour block average
CO	1357.5	30-day rolling average
NO_x	633.5	24-hour block average
CO	3000	8-hour block average
HCL	38.13	3-test run average

*Based on a 24-hour test run or any method approved by the Executive Secretary, which will provide 24-hour data.

24-hour block means the period of time between 12:01a.m. and 12:00 midnight.
8-hour block average means eight consecutive hours

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
Unit 3 Main Boiler Stack	PM_{10} (f)/PM_{10} (f+c)	Initial	Annual
	PM (f)	Initial	60-months**
	SO_2	Initial	CEM
	NO_x	Initial	CEM
	CO	Initial	CEM*
	H_2SO_4	Initial	Annual
	VOC	Initial	Annual
	Fluorides/HF	Initial	60-months
	Lead	Initial	60-months
	HCl	Initial	60-months

*or may use CEM equivalent, such as parametric monitoring that may be approved by the Executive Secretary

** or parametric monitoring that may be approved by the Executive Secretary

B. Testing Status (To be applied to the source listed above)

Initial: Initial compliance testing is required. The initial test date shall be performed as soon as possible and in no case later than 180 days after the start up of a new emission source, an existing source without an AO, or the granting of an AO to an existing emission source that has not had an initial compliance test performed. If an existing source is modified, a compliance test is required on the modified emission point that has an emission rate limit.

Annual: Test every year. The Executive Secretary may require testing at any time.

60-months: Test every five years. The Executive Secretary may require testing at any time.

CEM: After the initial test compliance shall be demonstrated through use of a Continuous Emissions Monitoring System (CEMs) as outlined in Condition #21 below. The Executive Secretary may require testing at any time.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

F. PM/PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201A, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}, for PM_{10} (filt+condensable) limit.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists (or for PM demonstration), then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, or 5D as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the Method 202 or other as approved by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration for PM (filterable) limit and shall be used for inventory purposes.

G. Sulfur Dioxide (SO_2)

40 CFR 60, Appendix A, Method 6, 6A, 6B, 6C, or other testing methods approved by the Executive Secretary.

H. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

I. Sulfuric Acid Mist (H_2SO_4)

40 CFR 60, Appendix A, Method 8, or other testing methods approved by the Executive Secretary.

J. Carbon Monoxide (CO)

40 CFR 60, Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

K. Volatile Organic Compounds (VOCs)

40 CFR 60, Appendix A, Method 25 or 25A

L. Hydrogen chloride (HCl)

40 CFR 60, Appendix A, Method 26 or 26A

M. Fluorides/Hydrogen fluoride (HF-hydrofluoric acid)

40 CFR 60, Appendix A, Method 26 or 26A

N. Lead

40 CFR 60, Appendix A, Method 12

O. Calculations for Testing Results

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

P. New Source Operation

For a new source/emission point, the production rate during all compliance testing shall be no less than 90% of the production rate listed in this AO. If the maximum AO allowable production rate has not been achieved at the time of the test, the following procedure shall be followed:

1. Testing shall be at no less than 90% of the production rate achieved to date.

2. If the test is passed, the new maximum allowable production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate.

3. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum AO production rate is achieved.

Q. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

11. Except for start-up, shut-down, planned/maintenance outage, or malfunction, differential pressure range at all times at the indicated points shall not exceed the following values

Unit 3 Dust Collectors

Source	differential pressure range across the dust collector (inches of water gage)
Fly Ash Storage Silo 1C Loading Spout Vent (EP-171)	0.5 to 12*
Fly Ash Storage Silo 1D Vent (EP-172)	0.5 to 12*
Coal Transfers Building #5 Vent (EP-127)	0.5 to 12*
Coal East Storage Silo Bay (EP-128)	0.5 to 12*

Coal West Storage Silo Bay (EP-129)..0.5 to 12*

*If differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis. The instrument shall be calibrated against a primary standard annually. Preventive maintenance shall be done quarterly on each baghouse.

12. Initial emission testing for mercury (Hg) is required within 180 days of commencing operation. Testing shall be performed using the following methods.

Emission	Testing Method*	Rate
Mercury (Hg)	40 CFR 60, Appendix A, Method 29	6.0×10^{-6} lb/MWhr

* or other testing methods approved by the Executive Secretary

The mercury content of any coal burned in Unit 3 shall be monitored and recorded based on "as-fired" monthly composite. Certification of fuels shall be either by IPSC's own testing or test reports from the fuel marketer. For determining mercury content in coal, American Society for Testing and Materials (ASTM) Method D3684-01 or other method approved by the Executive Secretary, is to be used.

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If the initial emission testing for mercury is passed, the source can operate using coal with mercury content no greater than 110% of the tested mercury content without further testing. If the monthly composite analyses indicate mercury values greater than 110% of the initial emission test, IPSC shall immediately arrange a new emission test for mercury at the higher mercury value within 60 days. Upon verification of compliance with mercury limit, new coal with a mercury content value no greater than of 110% of the last tested value shall then be allowed without further emission testing. No such emission testing is required if IPSC installs and operates a continuous mercury emissions analyzer.

13. Visible emissions from the following emission points shall not exceed the following values:

A. All baghouses at dust collectors' exhausts- 10% opacity
B. All other points - 20% opacity covered under this AO

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. Visible emissions from mobile sources and intermittent sources shall use procedures similar to Method 9

For sources that are subject to NSPS, opacity standards shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.

14. IPSC shall abide by a boiler manufacturer written instruction and/or written procedure developed and maintained by IPSC for the Unit 3 main boiler startup, shutdown, and malfunction periods.

15. The following Unit 3 boiler production and/or consumption limits shall not be exceeded:

A. 9050 million British Thermal Units (MMBtu) per hour full load heat input rate for Unit 3 boiler, using Higher Heating Value HHV of the fuel.

B. 3,541,248 tons of coal burned per rolling 12-month period

Consumption shall be determined by the main boiler control system database. The records of consumption shall be kept on a daily basis.

Roads and Fugitive Dust

16. IPSC shall abide by a fugitive dust control plan acceptable to the Executive Secretary for control of all dust sources associated with the addition of Unit 3 at the Intermountain Power Generation site. IPSC shall submit fugitive dust control plan to the Executive Secretary, attention: Compliance Section, for approval within 90 days of the date of this AO. This plan shall contain sufficient controls to prevent an increase in PM_{10} emissions above those modeled for this AO. The limitations and conditions in the fugitive dust control plan shall not be changed.

    Visible fugitive dust emissions from Unit 3 haul-road traffic and mobile equipment in operational areas shall not exceed 20% opacity. Visible emissions determinations for traffic sources shall use procedures similar to Method 9. The normal requirement for observations to be made at 15-second intervals over a six-minute period, however, shall not apply. Six points, distributed along the length of the haul road or in the operational area, shall be chosen by the Executive Secretary or the Executive Secretary's representative. An opacity reading shall be made at each point when a vehicle passes the selected points. Opacity readings shall be made ??? vehicle length or greater behind the vehicle and at approximately 1/? the height of the vehicle or greater. The accumulated six readings shall be averaged for the compliance value.

Fuels

17. The owner/operator shall use either bituminous or blend of bituminous and subbituminous coals as a primary fuel, blended to meet emission performance standards. The owner/operator shall use fuel oil during the startups, shutdowns, maintenance, upsets conditions and flame stabilization in the Unit 3 9050 x 10^6 Btu/hr boiler. The owner/operator may blend self-generated used oil with coal at the active coal pile reclaim structure providing record that self-generated used oil has not been mixed with hazardous waste.

18. The sulfur content of any fuel oil burned shall not exceed:

    0.85 lb per 10^6 Btu heat input for fuel used in the Unit 3 9050 x 10^6 Btu/hr boiler

    The sulfur content of fuel oil shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by IPSC's own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

19. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18, Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which

Construction in Commenced After September 18, 1978), Y, 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants), and 40 CFR 64 (Compliance Assurance Monitoring for Major Stationary Sources) apply to this installation.

20. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Monitoring - General Process

21. The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMs) on the main boilers stacks and SO_2 removal scrubbers inlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, CO, and NO_x emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170.

Records & Miscellaneous

22. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

23. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

24. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.airquality.utah.gov/

The annual emissions estimations below are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for the entire Unit 3 operations are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10} (filterable)	617.15
B.	SO_2	3,963.9
C.	NO_x	2775
D.	CO	5946
E.	VOC	107
F.	H_2SO_4	174
G.	Lead	0.79
H.	Total Reduced Sulfur	29
I.	Reduced Sulfur Compounds	29
J.	HAPs	
	Mercury	0.024
	Hydrochloric Acid (HCL)	167.01
	Fluorides/HF	20
	Total HAPs	199