TransAlta Centralia Generation, LLC

Centralia Plant

Title V Basis Statement

DRAFT Issued: May 15, 2009

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

PERMIT #:	SW98-8-R3
PREPARED FOR:	TransAlta Centralia Generation, LLC Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PLANT SITE:	Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PERMIT ENGINEER:	Clinton H. Lamoreaux, Air Quality Engineer
REVIEWED BY:	Paul T. Mairose, Chief Engineer

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I. GENERAL INFORMATION AND CERTIFICATION

1. Company Name: TransAlta Centralia Generation, LLC

2. Facility Name: Centralia Plant

3. Contact Person: Doug Jackson, President

4. Inspection Contact Person: Dan Zandell, Environmental Engineer

5. Unified Business Identification Number: 409-000-070

6. SIC Number: 4911

7. Basis for Title V Applicability:

The Centralia Steam Electric Generating Plant (Coal Plant) and the Combustion Turbine Facility (collectively know as the Centralia Plant) has the potential to emit more than 100 tons per year of sulfur dioxide, nitrogen oxides, particulate matter with an aerodynamic diameter less than 10 microns, particulate matter with an aerodynamic diameter less than 2.5 microns, and carbon monoxide which are criteria air pollutants listed under section 302 of the Federal Clean Air Act, more than 100 tons per year of volatile organic compounds (VOCs), and the potential to emit more than 25 tons per year of all hazardous air pollutant (HAP) emissions combined, which are listed under Section 112 of the Clean Air Act.

8. Current Permitting Action:

This Title V Air Operating Permit is being issued in response to a Title V renewal application submitted by TransAlta Centralia Generation, LLC in accordance with the deadline contained in Air Operating Permit SW98-8-R2-B. The Air Operating Permit issued in response to TransAlta's renewal application will be updated as appropriate and will include new permit terms related to Air Discharge Permit 08-2779 issued on March 12, 2008 for the Journal Shop.

9. Attainment Area:

The Centralia Plant is located in an area that is in attainment for all criteria pollutants.

10. Facility Description:

<u>Coal Plant</u>

The Centralia Coal Plant generates electric energy from steam driven turbines. Pulverized coal is combusted in the boilers of the two units to create heat that generates pressurized steam used in the turbines. Combustion of coal produces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants (HAPs) in sufficient quantities to designate the facility as a Title V source of air pollutants.

Until May 4, 2000, PacifiCorp owned the largest share of the Centralia Plant and operated the facility on behalf of all eight utility owners. As of May 4, 2000, TransAlta Centralia Generation, LLC took over ownership of the plant. The plant consists of twin 702.5 net

MW units identified as Unit #1 and Unit #2 (Acid Rain Program designations BW21 and BW22 respectively) which are the source of nearly all emissions released from the facility. An auxiliary boiler is used to provide steam for starting the main coal-fired boilers when both are off line or auxiliary steam is not sufficiently available from a unit that is operating. Coal is supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and is stacked and reclaimed in the Centralia Plant's coal handling yard. A small portion of low-sulfur coal is supplied from the Powder River Basin in Wyoming to blend with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure the hourly SO_2 emission limit continues to be met.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESPs) in series on each unit. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Emissions of other gaseous pollutants are minimized through good combustion practices. A portion of the fly ash captured in the ESPs is sold and shipped off site while the balance is stockpiled or (in the future) trucked to the Centralia Mine landfill site. Bottom ash is also sold, stockpiled, or (in the future) returned to the Centralia Mine landfill site. Additional emission points include the cooling towers, coal storage and handling yard, emergency diesel generators, mist eliminators for turbine lube oil ventilation exhaust, and maintenance activities.

The Centralia Coal Plant's two units can operate continuously 24 hours per day, 7 days per week. One or the other, and occasionally both, of the units are taken off line for maintenance purposes as conditions dictate, for economy, or reserve shut down. The auxiliary boiler operates only as needed, which is typically less than 120 hours per year.

Combustion Turbine Facility

Construction of the combustion turbine project commenced in 2001 and was completed during the summer of 2002. The project was permitted as a major modification to an existing major source. The Combustion Turbine Facility consists primarily of four General Electric (GE) LM6000 Sprint combustion turbines rated at 47 MW. Each turbine is equipped with a fired heat recovery steam generator (HRSG). Steam from all four HRSGs is used to power a steam turbine rated at 80 MW. The facility can produce up to 268 MW of electrical output at full load.

The turbines can be brought up to full load in less than 10 minutes, allowing this facility to operate as a peaking power plant. A 20.9 MMBtu/hr natural gas fired auxiliary boiler is operated when necessary to remove ice and prevent ice formation from the turbine inlets when steam is not available from the steam system (HRSGs), to start the steam turbine, and to supply gland steam to the steam turbine during steam turbine operation. A 1,000 kW black stop generator powered by a 1,448 hp diesel engine will be used to provide backup electricity in the event of a plant shutdown during a total electrical grid failure.

NO_X emissions from the combustion turbines and duct burners are controlled by a selective catalytic reduction system. CO emissions from the combustion turbines and duct burners are controlled by an oxidation catalyst.

11. SWCAA Air Discharge Permits and Consent Order(s):

The following table lists each Air Discharge Permit and Consent Order(s) issued for this facility. Permits or Orders in bold contain no active requirements. The requirements may have been superseded, may have been of limited duration, or the equipment may have been removed.

Order/Permit Number	App. #	Date Issued	Description
69-1107LET	L-1	11-7-69	Approval to construct Units #1 and #2
72-0804LET	N/A	8-4-72	Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing
72-0914LET	N/A	9-14-72	Approval given for operation at 400 MW
72-0610LET	N/A	10-6-72	Approval given for operation at 500 MW
72-1017LET	N/A	10-17-72	Approval to operate Unit #2 at full load for 48 hour demonstration
72-1102LET	N/A	11-2-72	Approval to operate Unit #1 at same load as Unit #2
72-1211LET	N/A	12-11-72	Approval given for operation of each unit up to 500 MW, PM not to exceed 0.06 gr/dscf
73-0329LET	L-49	3-29-73	Approval to install SO_3 conditioning system to aid PM removal in Koppers ESPs
73-0413LET	L-50	4-13-73	Approval to install second set of ESPs as pilot test
73-0426LET	N/A	4-26-73	Regulatory Order requiring testing to provide additional information on SO_3 conditioning system
73-0504LET	N/A	5-4-73	Required testing and reporting for ESP pilot test program
73-0522LET	N/A	5-22-73	Modified dates and operating conditions specified in 4-4-73 letter
73-0611LET	N/A	6-11-73	Approval to operate Unit #1 at up to 700 MW w/ PM $\leq$ 0.06 gr/dscf
74-0702LET	L-50R	2-7-74	Approved design and installation of second set of ESPs
74-0222LET	N/A	2-22-74	Revision to clarify language in 2-7-74 letter
74-38	N/A	3-25-74	Specifies testing on Unit #2
74-38A	N/A	5-2-74	Extends high load testing days to 30
87-934	N/A	8-26-87	Order of Violation – Exceedance of 1,000 ppm SO_2 limit, inconsistent with 1969 application, penalties levied, required to sample coal, stack SO_2.
87-934-STAY	N/A	9-21-87	Order staying for 18 months requirements for SO_2 sampling, coal S sampling, and withdrawing Order of Violation 87-934 if compliance with ambient SO_X limits met despite being above 1,000 ppm limits.

Order/Permit Number	App. #	Date Issued	Description
88-934	N/A	2-24-88	Order, Withdrawal of Stay, and Modification of Order of Violation - Required to study lime injection, blend and wash coal install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility.
88-934B	N/A	7-14-98	Variance and Modification of Order – Modified SO_2 averaging period, required ambient modeling and collection of meteorological data.
88-934C	N/A	10-24-99	934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites
90-934D	N/A	11-9-90	Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991.
90-934E	N/A	4-5-91	Withdrawal of Petition, Surrender of Variance, and Order - terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.
95-1787	N/A	8-25-95	RACT order limiting SO_2 emissions to 1.1 lb/MMBtu
96-1872	N/A	3-20-96	Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.
97-2057	N/A	12-8-97	Determination of SO_2, NO_X, CO and PM RACT, SO_2 and NO_X controls
97-2057R1	N/A	12-26-98	Revision of RACT determination

Order/Permit Number	App. #	Date Issued	Description
99-2187	N/A	2-1-99	Stay Order extending the date when procurement contract for Unit #1 control technology must be signed by 60 days (new date May 31, 1999).
01-2350	L-480	5-30-01	Minor source permit for combustion turbine project. Does not address PM or NO_X emissions
PSD-01-01	N/A	2-22-02	PSD permit for combustion turbine project – addresses PM and NO_X emissions
01-2403	L-490	2-27-02	Replacement of the Unit 1 and Unit 2 Turbine Lube Oil Mist Eliminators and Replacement of Two Rotary Fly Ash Unloaders With a Single Pug Mill
01-2350R1	L-496	5-6-02	Modification of 01-2350 primarily to increase SO_2 limit to account for higher sulfur content in natural gas
PSD-01-01 Amendment 1	N/A	1-30-03	Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler
01-2350R2	L-505	preliminary	Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.
PSD-01-01 Amendment 2	N/A	6-11-04	Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required.
01-2350R3	L-552	5-12-05	Modification of source testing and RATA frequencies for Combustion Turbine Facility
05-2612	L-556	7-15-05	Expansion of West Coal Unloading Facility with addition of 1 hopper
05-2636	L-565	11-23-05	Installation of FGD Bleed Treatment Lime Storage Silo
07-2712	L-590	2-7-07	Modification of West Coal Unloading Facility with surge capacity addition
07-2749	L-603	9-26-07	Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility
01-2350R4	L-608	1-18-08	Elimination of 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) limit was retained.
08-2779	L-613	3-12-08	Replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donaldson Torit cartridge style baghouse rated at 4,000 cfm in the Journal Shop

II. EMISSIONS UNIT DESCRIPTIONS

Summary Table

EU #	Generating Equipment	Emission Control
EU-1	Unit #1 Boiler (BW21) – 702.5 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber
EU-2	Unit #1 Boiler (BW22) – 702.5 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber
EU-3	Auxiliary Boiler – 170 MMBtu/hr, oil-fired	Fuel consumption limit
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facilities Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure
EU-5	Turbine Lube Oil Mist Vent #1	Turbine Lube Oil Mist Eliminator #1
EU-6	Turbine Lube Oil Mist Vent #2	Turbine Lube Oil Mist Eliminator #2
EU-7	Combustion Turbine 30 – GE LM6000 with 105 MMBtu/hr of duct firing capability	CO: Oxidation catalyst NO_X: Selective catalytic reduction system VOC: Oxidation catalyst PM: No controls SO_2: No controls
EU-8	Combustion Turbine 40 – GE LM6000 with 105 MMBtu/hr of duct firing capability	CO: Oxidation catalyst NO_X: Selective catalytic reduction system VOC: Oxidation catalyst PM: No controls SO_2: No controls
EU-9	Combustion Turbine 50 – GE LM6000 with 105 MMBtu/hr of duct firing capability	CO: Oxidation catalyst NO_X: Selective catalytic reduction system VOC: Oxidation catalyst PM: No controls SO_2: No controls

EU #	Generating Equipment	Emission Control
EU-10	Combustion Turbine 60 – GE LM6000 with 105 MMBtu/hr of duct firing capability	CO: Oxidation catalyst NO_X: Selective catalytic reduction system VOC: Oxidation catalyst PM: No controls SO_2: No controls
EU-11	Black Stop Diesel Generator Engine – 1,445 hp diesel engine	Operating hours limit
EU-12	BHP Auxiliary Boiler – 20.9 MMBtu natural gas fired package boiler	Low-NO_X burners, no add-on controls
EU-13	Journal Shop Welding	Journal Shop Welding Filter

Collectively EU-1, EU-2, EU-3, EU-4, EU-5, & EU-6 comprise the "Coal Plant." EU-7, EU-8, EU-9, EU-10, EU-11, & EU-12 comprise the "Combustion Turbine Facility."

Detailed Descriptions

EU-1 Unit #1 Boiler

EU-1 consists of the Unit #1 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit #1 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 383 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2002. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

The following individual pieces of equipment are associated with EU-1:

Equipment	Facility Designation
One boiler for Unit #1	Unit #1 or BW21
Two ESP units in series	Koppers 11 & 12; Lodge-Cottrell 11A & 12A
Unit #1 wet scrubber	FGD #1

Construction of EU-1 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU-1's initial turbine roll occurred August 6, 1971. EU1 commenced commercial operation in September 1971.

EU-2 Unit #2 Boiler

EU-2 consists of the Unit #2 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit #2 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 383 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2001. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

The following individual pieces of equipment are associated with EU-2:

Equipment	Facility Designation
One Boiler for Unit #2	Unit #2 or BW22
Two ESP units in series	Koppers 21 & 22; Lodge-Cottrell 21A & 22A
Unit #2 wet scrubber	FGD #2

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU2 commenced commercial operation in September 1972.

EU-3 Auxiliary Boiler

EU-3 consists of the auxiliary boiler which is used to provide auxiliary steam throughout the plant when sufficient auxiliary steam is not available from either Unit #1 or Unit #2, such as during cold startup. The auxiliary boiler is a Babcock & Wilcox watertube steam boiler (National Board number 23173, Washington State ID number 26415-71W) with a rated capacity of 115,000 lb/hr of steam and 170 MMBtu/hr. It combusts #2 fuel oil, also known as distillate grade diesel fuel, to produce steam at 150 psig and 500°F and discharges flue gases through a 5 ft diameter steel stack 250 ft in height. EU-3 emits NO_X, SO_2, CO, PM, and VOCs from combustion of #2 fuel oil that contains a maximum of 0.5% sulfur by weight.

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968.

EU-4 Material Handling

EU-4 consists of all coal handling equipment and operations on the Centralia Plant site, the ash collection and load-out facilities, the FGD Bleed Treatment Lime Storage Silo, and the Limestone Ball Mill. The coal handling equipment receives and stores the coal, reclaims coal from storage piles, and distributes the coal throughout the plant. Historically, coal has been received from the adjacent coal mine and delivered from the Powder River Basin. Most of the coal combusted in the Centralia Plant has been obtained from the adjacent TransAlta Centralia Mining (TCM) mine, which processed coal at its preparation plant and transferred the coal by conveyor to the Centralia Plant. This mine is currently closed. Coal is received by rail car at the East Coal Unloading Facility and the West Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Most of the coal is received by the East Coal Unloading Facility permitted in 2007. In 2007 the permittee received an Air Discharge Permit to construct the East Coal Unloading Facility. A traveling bucket-wheel stacker-reclaimer transfers yard conveyor transported coal to or from ready storage piles. In addition, a coal blending system installed in 2001 supplies coal to the plant from the ready storage pile. Dust suppression is provided to minimize generation of fugitive dust as coal is transported to the silos and pulverizers.

Fly ash is collected in storage silos and sent off-site via one of two load-out facilities. A portion of the fly ash is sold and loaded into trucks by an off-site contractor who is contractually responsible to the permittee for operation and air quality compliance of these truck-loading facilities at the Plant. Permittee is ultimately responsible for compliance under the Clean Air Act at this facility. The other load out operated by the Plant is used to dispose of fly ash in the TCM mine. Bottom ash is dewatered in settling tanks and loaded while damp into trucks for transport to the TCM mine as backfill or sold for off site use.

The following individual pieces of equipment are associated with EU-4:

Equipment	Facility Designation
West Coal Unloading Facility	West CUF
East Coal Unloading Facility	East CUF
Twelve coal conveyors	Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, & 22
One bucket-wheel stacker-reclaimer	Stacker-reclaimer
Coal blending system	
Chemical stabilizing dust suppression systems at CUF and #5 reclaim	(N/A)
Eight coal silos for each unit	Silos 11-18 (Unit #1), 21-28 (Unit #2)
Coal surge bin	(N/A)
Four bottom ash dewatering bins	Bins 11, 12, 21, 22
Various mobile machinery	(N/A)
Four fly ash bins	Bins 11, 12, 13, 14
	Bin 11 – Unclassified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
	Bin 12 – Classified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
	Bins 13 and 14 – reject material with one unloader each
FGD Bleed Treatment Lime Storage Silo	Same
Limestone Ball Mill	Same

West Coal Unloading Facility Details

Coal drops from coal rail cars into five below-grade hoppers. Five conveyor belts transfer the coal from the below-grade hoppers to the conveyor belt that feeds the power plant stockpiles. Two of the five have been modified to have the capability of transferring coal to an alternative belt feeding a stacker conveyor for stockpiling in a surge pile. The surge pile would be fed back onto the conveyor belt that feeds the power plant stockpiles between unloading events. The West Coal Unloading Facility and conveyor transfer points are not fully enclosed and therefore are potential sources of fugitive dust. The West Coal Unloading Facility will be maintained operational as a backup in case there are operational problems with the East Coal Unloading Facility.

The five below-grade hoppers are each associated with a conveyor belt that transfers the coal from the hopper to a conveyor belt system that feeds the power plant stockpiles. The entire unloading facility measures slightly over 50' in length. The conveyor belt system that feeds the power plant stockpiles consists of belts A, B, C, and D. The following transfer points are associated with the West Coal Unloading Facility:

1. Rail car to below-grade hopper
2. Below-grade hopper to hopper conveyors (BF-1, BF-2, BF-3, BF-4, and BF-5)
3. Hopper conveyors (BF-1, BF-2, BF-3, BF-4, and BF-5) to Conveyor Belt A
4. Hopper conveyors (BF-1 and BF-2) to Belt C-6A (which feeds the Stacker Conveyor C-6B) (new)
5. Conveyor Belt C-6A to Stacker Conveyor C-6B (new)
6. Stacker Conveyor C-6B to Unloading Surge Pile/Hopper (new)
7. Unloading Surge Pile/Hopper to Conveyor Belt C-6C (new)
8. Conveyor Belt C-6C from Unloading Surge Pile to Conveyor Belt A (new)
9. Conveyor Belt A to Conveyor Belt B

10. Conveyor Belt B to Conveyor Belt C
11. Conveyor Belt C to Convey Belt D
12. Conveyor Belt D to Stacker
13. Stacker to coal pile

The maximum coal unloading rate is 1,800 tons per hour.

East Coal Unloading Facility Details

The East Coal Unloading Facility consists of two below-grade hoppers, each associated with a drag flight conveyor that transfers coal to an interim conveyor that feeds the new radial stacker or feeds directly into the coal blending system. The radial stacker will transfer coal to the plant stockpiles. Coal in the coal stockpiles will be dozed to the coal blending/plant feed conveyors. The following transfer points are associated with the East Coal Unloading Facility:

1. Rail car to below-grade hoppers (2)
2. Below-grade hoppers to apron feeders
3. Apron feeders to Conveyor 8A
4. Conveyor 8A to Conveyor 8B (stacker)
5. Conveyor 8B (stacker) to coal stockpile or Conveyor 8C
6. Conveyor 8C to existing ground level reclaims 3, 3A
7. Reclaims 3, 3A to existing Conveyor 4 or 4A (which feed the plant)

Coal unloaded in the East Coal Unloading Facility passes through up to 6 new drop points that could create fugitive dust. The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity.

FGD Bleed Treatment Lime Storage Silo Details

The lime silo is located immediately southeast of the Unit #1 scrubber vessel. The silo is pneumatically loaded from trucks at a rate of approximately 16.7 tons per hour. Specific silo and associated dust collector information is listed below.

Silo Make/Model:	USFilter Lime Silo; WHM® Bulk Chemical Storage; Model T-1
Silo Capacity:	5,600 cubic feet
Silo Height:	53'1" without dust collector, 58' with dust collector
Dust Collector Make/Model:	C.P. Environmental Filters, Inc. / model 36-CTBFD-009-CM-30
Number of Bags:	9 cartridge style pleated "bags" measuring 6" in diameter by 36" l long
Cleaning Method:	Reverse Pulse-Jet
Cloth Area:	270 ft^2
Filter Media:	8.5 oz. pleated spun bonded polyester felt with PTFE membrane laminated to the exterior surface of the fabric
Design Exhaust Flow:	600 acfm

The manufacturer warrants that the particulate matter concentration in the effluent gas will not exceed an average of 0.005 gr/acf based on an inlet loading of 10 gr/acf.

Limestone Ball Mill Details

The Limestone Ball Mill is located in the ground floor of the FGD Building. The Limestone Ball Mill crushes limestone transferred from the limestone storage silo with water to form a limestone slurry for use in the Flue Gas Desulfurization systems. The Limestone Ball Mill is fully enclosed and is not a potential source of particulate matter emissions (the process is fully enclosed and water is injected at the upstream end of the ball mill), however it is an "affected facility" for the purposes of Title 40 Code of Federal Regulations (CFR) Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Ball mill processing capacity:	41 tons per hour
Manufacturer:	Svedala Industries (now known as Metso Minerals)
Serial number:	49663
Manufacture date:	May 2000
Installation date:	September 2001

EU-5 Turbine Lube Oil Mist Vent #1

The Unit #1 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator #1 is an Advanced Environmental Systems Air-Clear^{TM} Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

EU-6 Turbine Lube Oil Mist Vent #2

The Unit #2 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator #2 is an Advanced Environmental Systems Air-Clear™ Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

EU-7 Combustion Turbine 30

Combustion Turbine 30 is a General Electric LM6000 Sprint natural gas fired combustion turbine (serial number 191-314) equipped with a fired heat recovery steam generator (HRSG 30). The turbine utilizes water injection to control the formation of nitrogen oxides (NO_X) prior to control by a selective catalytic reduction system. The selective catalytic reduction system was manufactured by Peerless Manufacturing Company. CO and VOC emissions are controlled by an oxidation catalyst manufactured by Haldor Topsoe A/S. The turbine is fired solely on natural gas at a rate of up to 464.3 million British thermal units per hour (MMBtu/hr). The turbine has a nominal electrical generating capacity of 47 MW. The permittee expects to operate the turbine whenever indicated by economic conditions. LM6000 Sprint turbines can be brought to full load in less than 10 minutes, enabling the combustion turbine plant to operate as a peaking power plant.

HRSG 30 is a horizontal tube-and-fin "once through" heat recovery steam generator used to generate steam from the exhaust of Combustion Turbine 30. Combustion Turbine 30 can be operated independently from HRSG 30 (simple-cycle) or with HRSG 30 (combined cycle). HRSG 30 is equipped with natural gas fired duct burners rated at 105 MMBtu/hr. The duct burners supply supplemental heat and produce additional steam as necessary. A single steam turbine utilizing the combined steam from all four HRSGs has been installed to produce approximately 80 MW of power.

Construction of the combustion turbine project commenced in 2001 and completed with TransAlta's declaration of commercial operation on August 12, 2002.

EU-8 Combustion Turbine 40

Combustion Turbine 40 is a General Electric LM6000 Sprint natural gas fired combustion turbine (serial number 191-317) equipped with a fired heat recovery steam generator (HRSG 40). The turbine utilizes water injection to control the formation of

nitrogen oxides (NO_X) prior to control by a selective catalytic reduction system. The selective catalytic reduction system was manufactured by Peerless Manufacturing Company. CO and VOC emissions are controlled by an oxidation catalyst manufactured by Haldor Topsoe A/S. The turbine is fired solely on natural gas at a rate of up to 464.3 million British thermal units per hour (MMBtu/hr). The turbine has a nominal electrical generating capacity of 47 MW. The permittee expects to operate the turbine whenever indicated by economic conditions. LM6000 Sprint turbines can be brought to full load in less than 10 minutes, enabling the combustion turbine plant to operate as a peaking power plant.

HRSG 40 is a horizontal tube-and-fin "once through" heat recovery steam generator used to generate steam from the exhaust of Combustion Turbine 40. Combustion Turbine 40 can be operated independently from HRSG 40 (simple-cycle) or with HRSG 40 (combined cycle). HRSG 40 is equipped with natural gas fired duct burners rated at 105 MMBtu/hr. The duct burners supply supplemental heat and produce additional steam as necessary. A single steam turbine utilizing the combined steam from all four HRSGs was installed to produce approximately 80 MW of power.

Construction of the combustion turbine project commenced in 2001 and completed with TransAlta's declaration of commercial operation on August 12, 2002.

EU-9 Combustion Turbine 50

Combustion Turbine 50 is a General Electric LM6000 Sprint natural gas fired combustion turbine (serial number 191-327) equipped with a fired heat recovery steam generator (HRSG 50). The turbine utilizes water injection to control the formation of nitrogen oxides (NO_X) prior to control by a selective catalytic reduction system. The selective catalytic reduction system was manufactured by Peerless Manufacturing Company. CO and VOC emissions are controlled by an oxidation catalyst manufactured by Haldor Topsoe A/S. The turbine is fired solely on natural gas at a rate of up to 464.3 million British thermal units per hour (MMBtu/hr). The turbine has a nominal electrical generating capacity of 47 MW. The permittee expects to operate the turbine whenever indicated by economic conditions. LM6000 Sprint turbines can be brought to full load in less than 10 minutes, enabling the combustion turbine plant to operate as a peaking power plant.

HRSG 50 is a horizontal tube-and-fin "once through" heat recovery steam generator used to generate steam from the exhaust of Combustion Turbine 50. Combustion Turbine 50 can be operated independently from HRSG 50 (simple-cycle) or with HRSG 50 (combined cycle). HRSG 50 is equipped with natural gas fired duct burners rated at 105 MMBtu/hr. The duct burners supply supplemental heat and produce additional steam as necessary. A single steam turbine utilizing the combined steam from all four HRSGs was installed to produce approximately 80 MW of power.

Construction of the combustion turbine project commenced in 2001 and completed with TransAlta's declaration of commercial operation on August 12, 2002.

EU-10 Combustion Turbine 60

Combustion Turbine 60 is a General Electric LM6000 Sprint natural gas fired combustion turbine (serial number 191-346) equipped with a fired heat recovery steam generator (HRSG 60). The turbine utilizes water injection to control the formation of nitrogen oxides (NO_X) prior to control by a selective catalytic reduction system. The selective catalytic reduction system was manufactured by Peerless Manufacturing Company. CO and VOC emissions are controlled by an oxidation catalyst manufactured by Haldor Topsoe A/S. The turbine is fired solely on natural gas at a rate of up to 464.3 million British thermal units per hour (MMBtu/hr). The turbine has a nominal electrical generating capacity of 47 MW. The permittee expects to operate the turbine whenever indicated by economic conditions. LM6000 Sprint turbines can be brought to full load in less than 10 minutes, enabling the combustion turbine plant to operate as a peaking power plant.

HRSG 60 is a horizontal tube-and-fin "once through" heat recovery steam generator used to generate steam from the exhaust of Combustion Turbine 60. Combustion Turbine 60 can be operated independently from HRSG 60 (simple-cycle) or with HRSG 60 (combined cycle). HRSG 60 is equipped with natural gas fired duct burners rated at 105 MMBtu/hr. The duct burners supply supplemental heat and produce additional steam as necessary. A single steam turbine utilizing the combined steam from all four HRSGs was installed to produce approximately 80 MW of power.

Construction of the combustion turbine project commenced in 2001 and completed with TransAlta's declaration of commercial operation on August 12, 2002.

EU-11 Black Stop Diesel Generator Engine

One "black stop" diesel generator engine rated at 1,448 hp is used to drive an electrical generator and provide up to 1,000 kW of backup electricity in the event of a combustion turbine plant shutdown during a total electrical grid failure. The generator would be operated to provide power to the combustion turbine lubrication pumps and steam turbine rotor to prevent damage from sudden cool-down. Such an event is considered to be extremely rare, and the permittee only expects to operate the generator as needed for periodic testing. Operation of this unit is restricted to 500 hours per year, including routine testing.

This engine is a Mitsubishi Heavy Industries model S12H-PTA, serial number 30396, manufactured July 2001.

EU-12 BHP Auxiliary Boiler

The BHP Auxiliary Boiler is a 20.9 MMBtu/hr Superior Boiler Works Scotch Marine (fire tube) Wetback model 6-X-2500-5150M boiler (serial number 14878) that is used to provide supplemental steam to remove ice and prevent ice formation at the turbine inlets, to start the steam turbine, and to supply gland steam to the steam turbine during steam turbine operation. This boiler is fired solely on natural gas.

The boiler is equipped with Industrial Combustion model LNDG-300P-2 burners rated at 21.0 MMBtu/hr. The burners are designed with internal flue gas recirculation (FGR) and have guaranteed NO_X emissions of 20 ppm @ 3% O_2 or less. CO emissions are guaranteed not to exceed 50 ppm @ 3% O_2.

The BHP Auxiliary Boiler was built in 2001.

EU-13 Journal Shop Welding

Coal journals used in the coal pulverizers are repaired in the Journal Shop. Repairs consist primarily of welding replacement metal onto the journals to replace metal worn off during normal use. TransAlta submitted Air Discharge Permit Application L-613 on February 4, 2008 for replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donald Torit cartridge style baghouse rated at 4,000 cfm. The purpose of the replacement was to improve worker hygiene in the Journal Shop, especially to reduce potential worker exposure to chromium welding fumes.

Journal Shop – Baghouse. Journal Shop welding electrode use is less than 12,000 pounds per year. The baghouse pickups will be positions in such a way to minimize exposure of welders to welding fumes. Most welding is expected to be shielded metal arc welding. The following baghouse details were available:

Make / Model:	Donaldson Torit / DFO 2-8
Filter Area:	1,520 square feet of cartridge style filters
Primary Filter Media:	Ultra-Web FR with a MERV rating of 13
# of Filters:	8
Secondary Filters:	Contains two 24" x 24" x 12" HEPA filters downstream of cartridge filters
Design Capacity:	4,000 cubic feet per minute @ 10" w.c., 70 °F
Installed:	September 10, 2008

III. EXPLANATION OF INSIGNIFICANT EMISSIONS UNIT DETERMINATIONS

Each emission unit listed as insignificant in the permit has been reviewed by SWCAA to confirm its status. The numbering system used to identify these emission units is consistent with internal Centralia Plant designations and does not necessarily use consecutive numbers. Emission units were determined to be insignificant as follows:

IEU-05 Emergency Diesel Generator #1

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287637
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit #1. The generator is operated for about ¼ hour each week for testing, and consumes less than 300 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4). The unit is also insignificant according to WAC 173-401-830(2)(b) because it operates less than 100 hours per year. Based on an EPA AP-42 §1.3 emission factor for sulfur oxides of 72 lb/10^3 gallons (0.5% sulfur content diesel fuel oil) and 300 gallons of fuel oil, the annual emissions are:

300 gal/yr * 72 lb/10^3 gal * (1 ton/2,000 lb) = 0.01 ton sulfur oxides/yr

Emissions of sulfur oxides are largest relative to its WAC 173-401-530(4) threshold (2.0 tons per year of sulfur oxides) than are emissions of any other pollutant.

IEU-06 Emergency Diesel Generator #2

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287629
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit #2. The generator is operated for about ¼ hour each week for testing, and consumes less than 300 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4). The unit is also insignificant according to WAC 173-401-830(2)(b) because it operates less than 100 hours per year. Based on an EPA AP-42 §1.3 emission factor for sulfur oxides of 72 lb/10^3 gallons (0.5% sulfur content diesel fuel oil) and 300 gallons of fuel oil, the annual emissions are:

300 gal/yr * 72 lb/10^3 gal * (1 ton/2,000 lb) = 0.01 ton sulfur oxides/yr

Emissions of sulfur oxides are largest relative to its WAC 173-401-530(4) threshold (2.0 tons per year of sulfur oxides) than are emissions of any other pollutant.

IEU-07 Emergency Diesel Fire Pump

Engine Rating:	220 horsepower
Engine Make / Model:	Cummins / NHS-6-1F

The pump is powered by a 220 hp diesel engine that is operated for about ¼ hour each week for testing. Less than 150 gallons of diesel fuel are consumed annually, producing emissions below the thresholds of WAC 173-401-530(4). The unit is also insignificant according to WAC 173-401-830(2)(b) because it operates less than 100 hours per year. Based on an EPA AP-42 §1.3 emission factor for sulfur oxides of 72 lb/10^3 gallons (0.5% sulfur content diesel fuel oil) and 150 gallons of fuel oil, the annual emissions are calculated to be:

150 gal/yr * 72 lb/10^3 gal * (1 ton/2,000 lb) = 0.005 ton sulfur oxides/yr

Emissions of sulfur oxides are largest relative to its WAC 173-401-530(4) threshold (2.0 tons per year of sulfur oxides) than are emissions of any other pollutant.

IEU-55B Maintenance Shops Welding Emissions

Maintenance welding is exempt from registration according to SWCAA 400-101(10) and did not require an approval. Emissions from this discharge point are less than 0.1 ton/yr, well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant. Based on a conservative estimate that no more than 2,000 lb of electrode is used annually in any one shop and the highest value emission factor of 82 lb/1,000 lb from EPA AP-42 Table 12.19-1, the annual emissions are calculated to be:

2,000 lb * (82 lb/1,000 lb) * (1 ton/2,000 lb) < 0.1 ton/yr

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers. They are categorically exempt insignificant emissions units under WAC 173-401-532(121) because of processing exclusively non-contact cooling water. Furthermore, the cooling towers do not use chromium-based water treatment chemicals. Sodium hypochlorite is used to treat circulating cooling water and is consumed and does not escape to the ambient air.

IEU-61 Cold Solvent Parts Washers

Eight parts washing solvent tanks are used at the Centralia Plant site for only non-chlorinated solvent, each tank ranging in size from 30 to 40 gallons. The tanks are covered by lids when parts are not actively loaded or unloaded into or out of the tanks. The parts washers emit minimal VOC emissions and are considered insignificant because only fugitive emissions are released consistent with the definition of insignificant emission units in WAC 173-401-530(1)(d) and because their emissions are below the 2.0 tons per year VOC threshold of WAC 173-401-530(4)(d). Based on solvent use of 12,000 lb/yr and a recycle rate of 92% estimated by the solvent recycle vendor, VOC emissions are calculated to be:

12,000 lb/yr * (1 - 0.92) * (1 ton/2,000 lb) = 0.48 tons per year VOC

IEU-71 Fuel Oil Storage Tank #1

This storage tank supplies fuel oil to the boilers for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-72 Fuel Oil Storage Tank #2

This storage tank supplies fuel oil to the boilers for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For an annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-73 Gasoline Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 41.3 lb/1,000 gal was derived for this tank. For an annual throughput of 15,000 gallons, VOC emissions are calculated to be:

15,000 gal * 41.3 lb/1000 gal * (1 ton/2,000 lb) = 0.31 tons per year VOC

IEU-74 Diesel Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.001 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.020 lb/1000 gal was derived for this tank. For an annual throughput of 16,000 gallons, VOC emissions are calculated to be:

16,000 gal * 0.020 lb/1000 gal * (1 ton/2,000 lb) = 0.0002 tons per year VOC

IEU-75 Emergency Diesel Generator #1 Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies emergency diesel generator #1. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For an annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-76 Emergency Diesel Generator #2 Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies emergency diesel generator #2. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-77 Emergency Diesel Fire Pump Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the emergency diesel fire pump. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.47 lb/1,000 gal was derived for this tank. For an annual throughput of 150 gallons, VOC emissions are calculated to be:

150 gal * 0.47 lb/1,000 gal * (1 ton/2,000 lb) = 0.00004 tons per year VOC

IEU-78 Limestone Silo

The limestone silo receives limestone shipments from trucks and feeds the ball mill for the FGD system. Particulate matter emissions are controlled by a Flex-Kleen model 30/36-PVBL-9-11 G vent filter (serial number 100770) located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. The conveyor to the silo has a capacity of 200 tons per hour and the ball mill has a capacity of 41 tons per hour, therefore the unit can operate up to 8,760*(41/200) = 1,796 hours per year. The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical for material handling silo filters), potential emissions are:

$$\frac{1{,}796\ \text{hours per year}}{\text{year}} * \frac{900\ \text{cubic feet}}{\text{minute}} * \frac{60\ \text{minutes}}{\text{hour}} * \frac{0.005\ \text{grains}}{\text{standard cu ft}} * \frac{1\ \text{pound}}{7{,}000\ \text{grains}} = \frac{69\ \text{pounds}}{\text{year}}$$

Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IEU-79 Lime Silo

The lime silo receives lime shipments from trucks and feeds the FGD system when necessary (e.g. ball mill is inoperable). Particulate matter emissions are controlled by a Flex-Kleen model 30-PVBL-9-11 G vent filter located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. This unit can receive approximately 25 tons per hour of material from a truck (1 truckload per hour). The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical for material handling silo filters), potential emissions are:

$$\frac{8{,}760 \text{ hours per year}}{\text{year}} * \frac{900 \text{ cubic feet}}{\text{minute}} * \frac{60 \text{ minutes}}{\text{hour}} * \frac{0.005 \text{ grains}}{\text{standard cu ft}} * \frac{1 \text{ pound}}{7{,}000 \text{ grains}} = \frac{338 \text{ pounds}}{\text{year}}$$

This unit typically operates one hour per day, so typical emissions are far less than 338 pounds per year. Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IV. EXPLANATION OF SELECTED PERMIT PROVISIONS AND GENERAL TERMS AND CONDITIONS

P11. Excess Emissions

[SWCAA 400-107, WAC 173-400-107]

WAC 173-400-107 and SWCAA 400-107 establish criteria and procedures for determining when excess emissions are considered unavoidable. Emissions that meet the requirements to be classified as unavoidable are still considered excess emissions and are reportable but are excused and not subject to penalty. Notification of excess emissions is required as soon as possible and shall occur by the next business day following the excess emissions event. Excess emissions due to startup or shutdown conditions are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been prevented through careful planning and design. Upset excess emissions are considered unavoidable if the permittee adequately demonstrates the upset event was not caused by poor or inadequate design, operation, maintenance, or other reasonably preventable condition, and the permittee takes appropriate corrective action that minimizes emissions during the event, taking into account the total emissions impact of that corrective action. Additional descriptions of potential excess emissions and how the permittee is expected to respond to those events are provided in requirements M10 and M16 - Startup, Shut Down, and Outage Operation Procedures.

G10. Portable Sources

[WAC 173-400-035, WAC 173-400-110(5), SWCAA 400-110(5) (SIP only), SWCAA 400-110(6) (Local Only)]

WAC 173-400-110(5) in the SIP (replaced in the State only rules by WAC 173-400-035) and SWCAA 400-110(6) establish procedures for approving the operation of portable sources of air emissions that locate temporarily at project sites. These requirements are general statewide standards, and apply to all portable sources of air contaminants. Common equipment subject to these conditions include emergency generators, engine-powered pumps, rock crushers, concrete batch plants, and hot mix asphalt plants that operate for a short time period at a site to fulfill the needs of a specific contract. Portable sources exempt form registration under SWCAA 400-101 are exempt from SWCAA 400-110 and not subject to the portable sources requirements. Among those categories listed in SWCAA 400-101 that are exempt, are operations with potential to emit less than 1 ton/yr of all criteria pollutants plus volatile organic compounds, combined.

V. EXPLANATION OF OPERATING TERMS AND CONDITIONS

Req. 1-8 General Standards for Maximum Emissions
[SWCAA 400-040, WAC 173-400-040, SWCAA 01-2350R4]

WAC 173-400-040 and SWCAA 400-040 establish maximum emission standards for various air contaminants. These requirements are general statewide standards, and apply to all sources of air contaminants. Therefore, these requirements apply to all emission units at the source, both EU and IEU. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the underlying requirements. The averaging time for the SO_2 standard of Req-6 is satisfied by 60-minute average values averaged over each clock hour consistent with the monitoring provisions of M9.

No specific monitoring was specified for requirement 7 because there are no specific monitoring requirements that can be used to encompass the whole range of potential concealment and masking scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including these prohibited items, at least annually. The permittee must make a reasonable inquiry to determine if concealment or masking has occurred during the reporting period in order to certify compliance.

Req. 9 Emission Standards for Combustion and Incineration Units
[SWCAA 400-050, WAC 173-400-050]

WAC 173-400-050 and SWCAA 400-050 establish maximum emission standards for selected emissions from combustion and incineration units. These requirements apply to all combustion and incineration units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs. The relevant combustion units identified by emission point are EU-1, EU-2, EU-3, EU-7, EU-8, EU-9, EU-10, EU-11, and EU-12.

Req. 10 Stack Sampling of Major Combustion Sources
[SWCAA 400-052]

SWCAA 400-052 requires that emissions testing be performed every two years to quantify emissions of the pollutant(s) for which the source has been designated major. These requirements apply to emission units EU-1 and EU-2 because sulfur dioxide, oxides of nitrogen, particulate matter, carbon monoxide, and volatile organic compound emissions are each greater than 100 tons per year, the threshold for designating a source as major under Title V.

Req. 11 Emission Standards for General Process Units
[SWCAA 400-060, WAC 173-400-060]

WAC 173-400-060 and SWCAA 400-060 establish maximum particulate matter emission standards for general process units. These requirements apply to all general process units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not

contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 12 Emission Standards for Certain Source Categories - Abrasive Blasting
[SWCAA 400-070(8)]

SWCAA 400-070 establishes emission standards for seven specific source categories. The requirements of SWCAA 400-070(8) apply due to the potential for infrequent abrasive blasting operations at the plant site. Abrasive blasting is required to be conducted inside a booth or structure designed to capture the blast grit, overspray, and removed material, except for blasting of outdoor structures and items too large to be handled inside an enclosure. Outdoor blasting is to be performed with either steel shot or an abrasive material containing less than 1 percent by mass material that would pass through a No. 200 sieve. Precautions to minimize emissions, such as enclosure of the area being blasted with tarps, are to be used for outdoor blasting.

No specific monitoring was specified for this requirement because there are no specific monitoring requirements that can be used to encompass the whole range of potential blasting scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including this requirement, at least annually. The permittee must make a reasonable inquiry to determine if prohibited activities have occurred during the reporting period in order to certify compliance.

Req. 13 Opacity Monitoring, and Reporting
[SWCAA 400-105(4)(a)(i) & (4)(e), WAC 173-400-105(5)(a)(i) & (5)(e)]

WAC 173-400-105(5)(a) & (5)(e) and SWCAA 400-105(5)(a) & (5)(e) require that fossil fuel-fired steam generators of 250 million Btu/hr or greater heat input without sulfur dioxide control equipment install a continuous monitor for opacity, and operate it in accordance with the requirements found in 40 CFR 51, Appendix P and 40 CFR 60, Appendices B - F, as appropriate. This requirement applies to emission units EU-1 and EU-2 only during a scheduled outage of the flue gas desulfurization system and anticipated startups. Anticipated startups exclude startups immediately (less than 12 hours) following a forced outage. This requirement does not establish a visible emission standard with a specified opacity value; Reqs-1 and 15 are the applicable requirements that set a visible emission standard expressed as an opacity value to be achieved. The evaluation method is presented in Appendix A of the Air Operating Permit.

Req. 14-19, 21-23, 25-26 Regulatory Order to Establish RACT
[SWCAA 97-2057R1]

The Regulatory Order to Establish Reasonably Available Control Technology (RACT) is the only remaining Order to apply to operations of EU-1 and EU-2 at this source because it explicitly supersedes all previous Orders applicable to those units. Section 34 of SWCAA 97-2057R1 specifies the effective date of the new PM limitation.

Following extensive analysis of what constitutes RACT for this source, SWCAA issued Regulatory Order to Establish RACT SWCAA 97-2057 to the Centralia Plant on December

8, 1997 to establish Reasonably Available Control Technology (RACT) emission limits for SO_2, NO_X, PM, and CO emissions from the plant. The Centralia Plant petitioned SWCAA for a modification of the NO_X emission limit, and SWCAA revised the RACT Order as SWCAA 97-2057R1 on February 26, 1998. This Order establishes RACT emission limits for SO_2, NO_X, PM, and CO emissions, restricts the annual consumption of fuel oil by the auxiliary boiler (EU-3), and supersedes all Orders previously issued to the Centralia Plant (see VI. Explanation of Obsolete and Future Requirements).

Section 36 of SWCAA 97-2057R1 (Requirement 15) establishes opacity limitations for the boilers (EU-1 and EU-2). The permittee operates opacity monitors in the ductwork upstream of the bypass stack. No correlation has been developed to describe the relationship between the opacity indicated by these monitors and the opacity of the FGD exhaust, therefore these monitors cannot be used to determine compliance with this requirement for the FGD exhaust.

Requirement 19 applies during normal operation. Emissions during startups, shutdowns, and outages of the FGD system are addressed by Requirement 20.

Requirement 26 contained an interim NO_X emission limit that applied only to calendar year 2002.

Req. 20, 43 Acid Rain Compliance Plan

[WAC 173-406-400, 40 CFR 72.40(a)]

40 CFR 72.40 and WAC 173-406-400 require that the Centralia Plant hold SO_2 allowances not less than the total annual emissions in tons of SO_2 from the affected units (EU-1, EU-2, EU-7, EU-8, EU-9, and EU-10) at the Centralia Plant. The Centralia Plant received an initial allocation of allowances only for BW21 (EU-1) and BW22 (EU-2). The EPA may reallocate the number of allowances assigned to individual units and between units; therefore, annual allowance allocations may change in the future. The number of allowances actually held by a source in an Acid Rain affected unit account may differ from the number initially allocated by U.S. EPA as allowances are bought and sold on the open market to cover actual emissions.

Req. 24 Acid Rain NO_x Reduction Early Election for Group 1, Phase II Boilers

[WAC 173-406-106, 40 CFR 76.7(a)(1)]

The Phase II emission limit of 0.40 lb/million Btu was effective January 1, 2008.

Req. 27 Acid Rain Primary Monitoring Provisions

[40 CFR 75.10(a)]

40 CFR 75.10(a)(1) through (3) requires that an Acid Rain affected unit be equipped with continuous emissions monitoring systems with an automated data acquisition and handling system for measuring and recording SO_2, NO_X, and CO_2 emissions, respectively, discharged to the atmosphere. 40 CFR 75.10(a)(4) requires such units to be equipped with a continuous opacity monitoring system with an automated data acquisition and handling system for measuring and recording the opacity of discharged emissions.

Opacity

40 CFR 75.14(b) exempts units utilizing a wet flue gas pollution control system from the opacity monitoring requirements if the owner or operator can demonstrate that condensed water vapor is present in the exhaust stream and would impede the accuracy of opacity measurements. The Centralia Plant has provided ample demonstration that condensed water vapor is present in sufficient quantities to interfere with an opacity monitor and is therefore exempt from the requirement to continuously monitor opacity from the scrubber flues.

The gas stream leaving the scrubbers is saturated with water. As the flue gas inevitably cools, water condenses out of the gas stream forming steam and water droplets. The results of testing conducted during November 2001 (6 runs during scrubber performance test) and December 2001 (9 runs during initial RATA) indicated that the flue gas was supersaturated. Condensed water vapor is clearly visible through the sample ports at the test platform.

Gaseous Pollutant Monitoring at Bypass Stack

SWCAA 97-2051R1 requires monitoring of SO_2 emissions from both the bypass and scrubber flues. Acid Rain rules do not require direct monitoring at the bypass stack. This policy is detailed in question "17.6 – Revised" from the Acid Rain Policy Manual (December 2000) in addition to the Acid Rain rules promulgated May 1, 2002. The CEMS may be located upstream. When a certified monitoring system is not maintained on the bypass stack, the maximum potential emissions must be reported for bypass hours.

Req. 28 Good Air Pollution Control Practices

[SWCAA 97-2057R1]

This requirement is meant to require reasonable practices to reduce emissions below the short-term emission limits provided in SWCAA 97-2057R1 when possible, and optimize use of the emission control equipment. The following paragraphs describe good air pollution control practices for minimization of SO_2, NO_X, and PM emissions from the coal-fired boilers

Sulfur Dioxide

The SO_2 emission control equipment is the Flue Gas Desulfurization (FGD) system or scrubber. Good air pollution control practice is to utilize recycle pumps as necessary to maintain SO_2 as low as practicable without allowing the SO_2 CEMS indication to drop to or below zero (below zero indications are possible due to minor instrument drift). A small amount of SO_2 must be maintained in the flue gas to assure that the gypsum that is produced is of marketable quality for manufacturing, and to prevent degradation or damage to the desulfurization system from scaling. If all SO_2 in the flue gas is reacted, the residual limestone can, in a short time period, cause scaling in the reaction vessel leading to reduced scrubbing efficiency and mechanical failure.

The original design specifications for the scrubber specify that three of the four recycle pumps would be in operation at any one time. The fourth recycle pump would be maintained as a maintenance spare and backup. The specification was based on the use of high sulfur coal from the Centralia Mine. When the plant is using low sulfur coal from the

Powder River Basin, SO_2 can be maintained at a minimum level with the use of less than three recycle pumps.

In addition to maintaining minimum SO_2 levels, at times it may not be possible to operate the design number of recycle pumps and spray levels due to operational problems including when:

1. Equipment problems require two pumps off-line for maintenance or repair activities; and
2. Equipment problems downstream of the scrubber (e.g. vacuum belt filter malfunctions, problems with reaction tank oxidation blowers) or upstream of the scrubber (e.g. reagent pump or ball mill failures) limit reagent addition or gypsum removal.

Such events should be reported as an upset condition and will be reviewed on an individual basis.

Nitrogen Oxides

The NO_X emissions control system is good boiler combustion practices and low NO_X burner modifications on the boilers. NO_X control is significantly different than add-on SO_2 control. NO_X control is an integral part of the combustion process. If the boiler is operated to minimize NO_X emissions, combustion efficiency decreases to the point of limiting electrical power output, increases coal combustion/megawatt which increases emissions of other pollutants (SO_2, PM, CO and VOCs) and increases slagging, sootblowing and maintenance costs from increased boiler tube repairs. Based on current information, good air pollution control practice for NO_X is balancing the varied factors and maintaining emissions below the RACT limitations.

Particulate Matter

The particulate matter (PM) emissions control systems are the two tandem electrostatic precipitators in series. In addition, the FGD system removes additional PM through the scrubbing process. Maintaining good precipitator performance is important in order to maintain the quality of the gypsum by-product necessary for sale for use in wallboard.

Req. 29 Pug Mill Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of fugitive particulate matter from this source at the time of permitting (2001). The only potential point of emissions from this source is fugitive during the transfer to trucks.

Req. 30 Turbine Lube Oil Mist Eliminators Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of visible emissions/lube oil mist from this source at the time of permitting (2001). The manufacturer literature for the Advanced Environmental Systems mist eliminator guarantees opacity levels of 5% or less. On-site observations have demonstrated that visible emissions from this source do not exceed 5%.

Using the conservative assumption of a 99.5% control efficiency (provided by Advanced Environmental Systems on a particle count basis), and 8,760 hours of operation per year, each turbine lube oil mist eliminator will emit up to 0.1 pounds of lube oil mist per year.

Req. 31, 32, 33, 34, 35, 36 Control of Particulate Matter from Coal Unloading
[SWCAA 07-2749]

Air Discharge Permit SWCAA 07-2749 was written in response to an Air Discharge Permit (ADP) application for installation of the East Coal Unloading Facility and modification of the operating limits for the West Coal Unloading Facility. These requirements represent BACT for control of particulate matter (coal dust) from the unloading of coal from rail cars at this facility.

Annual emissions of PM_{10} from the Coal Unloading Facility are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 07-2749) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k=1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

A control factor of 90% is applied to transfer points utilizing high pressure wet suppression to control fugitive dust (some pre-existing transfer points may be uncontrolled).

Req. 37, 38 Control of Particulate Matter from FGD Bleed Treatment Lime Storage Silo
[SWCAA 05-2636]

Air Discharge Permit SWCAA 05-2636 was written in response to an Air Discharge Permit (ADP) application for installation of a new hydrated lime storage silo. This silo was installed as part of a project to remove boron and zinc from the flue gas desulfurization (FGD) system scrubbing liquor. These requirements represent BACT for control of particulate matter (hydrated lime) from the pneumatic loading of hydrated lime into the silo.

Req. 42 NSPS NO_X Limit for Duct Burner Emissions
[40 CFR 60.44b]

Title 40 CFR Part 60.40b et seq. (Subpart Db) "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" establishes PM, NO_X and SO_2 emission standards as well as recordkeeping and reporting requirements for all new steam generating

units with a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr. The duct burners in each HRSG are rated at 105 MMBtu/hr, therefore this standard applies to the duct burners at this facility. The duct burners will burn only natural gas, therefore only the 0.2 lb/MMBtu NO_X limit is applicable.

Compliance with the NSPS NO_X limit is presumed when compliance with the NSR NO_X emission limits for the combustion turbine exhaust stacks is demonstrated using the CEMS or stack test data. See 40 CFR 60.46b(e).

Req. 41, 46 (second half), 54 NSPS Requirements for Combustion Turbines

[40 CFR 60 Subpart GG and 40 CFR 60.11]

Title 40 CFR Part 60.330 et seq. (Subpart GG) "Standards of Performance for Stationary Gas Turbines" establishes NO_X and SO_2 emission standards for all new stationary gas turbines with a heat input at peak load greater than 10.7 gigajoules per hour based on the lower heating value of the fuel fired. The heat input of each turbine at peak load is approximately 471 gigajoules per hour, therefore this standard applies to the gas turbines at this facility. This subjects the turbines to the general standards such as 40 CFR 60.11 in Req-34 as well as the specific requirements for the combustion turbines.

Req. 44, 46 (first half), 47, 48, 50-59, 64 Minor New Source Review Permit for Combustion Turbine Facility

[SWCAA 01-2350R4]

Air Discharge Permit SWCAA 01-2350 was written in response to an Air Discharge Permit (ADP) application for installation of the combustion turbine facility. Emissions of PM_{10} and NO_X exceeded the PSD significance threshold, therefore permitting of these emissions were addressed through the PSD permitting process and not in Air Discharge Permit SWCAA 01-2350. After the completion of permitting, new information concerning the sulfur content of natural gas in the region became available. This new information indicated that the annual average sulfur content of natural gas available to the permittee was significantly higher, and the total sulfur content more variable, than previously estimated. Air Discharge Permit SWCAA 01-2350R1 was written in response to an ADP application submitted by the permittee to revise the SO_2 emission limit consistent with this new information. Air Discharge Permit SWCAA 01-2350R2 was written in response to an ADP application submitted by the permittee to revise the specifications for the BHP Auxiliary Boiler. Air Discharge Permit SWCAA 01-2350R3 was written in response to an ADP application submitted by the permittee to revise the source testing and RATA schedules to be consistent with PSD-01-01 Amendment 2 and the Acid Rain Program rules. Air Discharge Permit SWCAA 01-2350R4 was written in response to an ADP application submitted by the permittee to eliminate the 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) was retained.

The emission limits and operating requirements in SWCAA 01-2350R4 represent BACT for SO_2, CO, VOCs, and toxic air pollutants at the time of permitting. Requirements 45 and 48 were included in both Air Discharge Permit SWCAA 01-2350R4 and the PSD permit (PSD-01-01 Amendment 2).

In accordance with Condition 11 of SWCAA Air Discharge Permit 01-2350R4, to calculate 24-hour average emission concentrations of ammonia, the average emission concentration during each of the 24 most recent consecutive operating hours (excluding excused upset events) shall be averaged. Emissions from non-consecutive operating hours shall not be averaged for comparison with the 24-hour emission concentration limit. For example, the 24-hour average ammonia concentration limit does not apply until the 24th hour following a unit startup.

Req. 45, 49, 50, 53, 57, 60-63, 65, 66 PSD Permit for Combustion Turbine Facility
[PSD-01-01 Amendment 2]

PSD permit PSD-01-01 was written in response to a PSD application for installation of the combustion turbine facility. PSD 01-01 Amendment 1 was written in response to a PSD application to approve the existing BHP Auxiliary Boiler because it differed from the one approved in the original PSD permit. PSD-01-01 Amendment 2 was written in response to a permit application to clarify the RATA frequency requirements. The PSD permit addresses emissions of PM_{10} and NO_X.

The emission limits and operating requirements in PSD-01-01 Amendment 2 represent BACT for PM_{10} and NO_X at the time of original permitting. In addition, the emission limits established in this permit are set at levels where ambient modeling indicated no adverse impact on ambient air quality or visibility. Specifically, Requirement 45 limits NO_X emissions on a daily basis because this is the highest emission rate for which visibility modeling was performed.

Requirements 65 and 66 are not associated with specific monitoring because the annual compliance certification provides adequate assurance of continuing compliance. Requirement 66 is a one-time requirement that will be verified by the first annual inspection following applicability. The permittee is required to certify compliance with all terms and conditions of the permit, including these items, at least annually. The permittee must make a reasonable inquiry to determine if the O/M manual has been maintained and NO_X compliance plan submitted in order to certify compliance.

Requirement 66 requires submission of a NO_X compliance plan. Although no time schedule is specified, it was expected that the NO_X compliance plan would be submitted in time to utilize the plan for compliance purposes (i.e. by the commencement of commercial operation). The requirement was penned by the Washington Department of Ecology (WDOE). WDOE and TransAlta have agreed that submittal of the plan at "about the time of transition to commercial operation" is appropriate so that the operational experience gained during commissioning can be utilized to prepare the plan.

The 3-hour average emission concentration limit specified in Req-45 only applies when there are 3 consecutive hours of emission data to average following a unit startup. This clarification was made by Mr. Richard Hibbard of the Washington Department of Ecology (the author of the underlying requirement) in an electronic mail message on January 31, 2003.

VI. EXPLANATION OF OBSOLETE AND FUTURE REQUIREMENTS

1. Obsolete SWCAA Regulatory Orders/Permits

SWCAA issued eight Orders and Air Discharge Permits to the permittee between 1972 and 1974 in response to a particulate matter control equipment testing program and Air Discharge Permit applications submitted for installation or modification of such equipment and for operations at the source. Seven Orders were issued to the permittee between 1987 and 1991 regarding the averaging period for the SWCAA SO_2 emission standard and a variance request by the source. These seven Orders are no longer applicable as described below. From 1995 through early 1998, three Regulatory Orders concerning Reasonably Available Control Technology (RACT) requirements were issued to the permittee, two of which are no longer applicable as described below.

A SWCAA Order dated December 11, 1972 required the PM emission level of 0.06 gr/dscf not to be exceeded at any time, and also established maximum operating levels during compliance testing of both units. An Order dated April 13, 1973 approved installation of additional ESP collection area and required that additional sections be designed and installed to control emissions to 0.06 gr/dscf. A SWCAA Order dated April 26, 1973 specified objectives of a particulate matter emission testing program, allowed operation at maximum output during a specified test schedule for Unit #1, and reiterated the 0.06 gr/dscf emission limit in the December 11, 1972 Order. An Order dated May 4, 1973 approved operation of Unit #2 at maximum output during a scheduled particulate matter emissions test and listed the objectives of the test program. A May 22, 1973 Order extended the test schedule for Unit #2. A SWCAA Order dated June 11, 1973 approved full output operation of Unit #1, and, not to be exceeded at any time, the particulate matter emission level of 0.06 gr/dscf.

These Orders were effectively replaced by a subsequent SWCAA Order (dated February 7, 1974 and revised on February 22, 1974) that approved installation of the Lodge-Cottrell ESPs in series following the original ESPs on both Units #1 and #2. This February 1974 Order approved continued operation at an emission level not to exceed 0.06 gr/dscf and required demonstration of satisfactory equipment performance within three months after startup of the new ESPs. Administrative Order 74-38 established a high-load testing schedule for Unit #2 not to exceed ten days commencing May 6, 1974. Although these Orders were not explicitly superseded until SWCAA 97-2057R1 was issued, the Orders dealing only with the testing program to improve and evaluate particulate matter collection became moot with the approval and subsequent performance demonstration of the Lodge-Cottrell ESPs.

The Centralia Plant disagreed with SWCAA's authority to establish via the February 1974 Order an emission limit more stringent than the state standard for particulate matter, 0.1 gr/dscf. SWCAA established the 0.06 gr/dscf emission limit consistent with "advances in the art" (the term that predates BACT) to not allow degradation of the control equipment and ensure meaningful emission reductions as intended under the Clean Air Act. Although all previous Orders have been superseded by Section 49 of SWCAA 97-2057R1, the 0.06 gr/dscf emission limit based on "advances in the art" was effective until the RACT limit of

0.010 gr/dscf become the applicable requirement for particulate matter emissions after December 31, 2001.

Order of Violation SWCAA 87-934 was issued for violations of the 1,000 ppm SO_2 emission limit based on average daily coal sulfur analyses, and required the permittee to implement coal analysis at twenty minute intervals, perform sampling of SO_2 emissions, and correlate the sampling results with the coal analyses. The Order suspended a civil penalty provided that no additional violations of the SO_2 emission standard occurred for one year. Stay of Order of Violation SWCAA 87-934-STAY stayed for up to 18 months from September 21, 1987 the requirements in SWCAA 87-934 for coal analysis and SO_2 emission sampling, and the civil penalty.

Order, Withdrawal of Stay, and Modification of Order of Violation SWCAA 88-934 required the Centralia Plant to install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility, blend and wash the coal supplied to its boilers, conduct a feasibility study of lime injection multiple burner technology to reduce SO_2 emissions, and comply with the SO_2 emission limit of 1,000 ppm averaged over a one week period. This Order, issued on February 24, 1988, withdrew the coal analysis and SO_2 emission sampling provisions and the civil penalty assessed by SWCAA 87-934. SWCAA 88-934 was amended by Variance and Modification of Order SWCAA 88-934B which granted a variance from the 1-hour averaging period of the SO_2 emission standard and established a weekly averaging period effective May 25, 1988 through November 25, 1989. SWCAA 88-934B required measured SO_2 emissions to be corrected to a dry basis, installation of meteorological monitoring equipment to be operated from October 1, 1988 through September 30, 1989, modeling of SO_2 emissions by an EPA approved dispersion model, and other minor modifications to 88-934.

SWCAA 88-934C Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites. SWCAA 90-934D Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991. Effective on April 5, 1991, SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.

SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order (issued on April 5, 1991) revoked an earlier Variance and restored compliance with the SO_2 standard over a 1-hour averaging period. It also established a procedure for determining compliance with the hourly SO_2 standard which defined an "excess SO_2 emission day" as 3 or more unique excess SO_2 emission hours during any continuous 24-hour period in the month, and an "SO_2 emission violation" as 3 or more unique excess SO_2 emission days occurring in a

calendar month. SWCAA 97-2057R1 supersedes Order No. SWCAA 90-934E along with its SO_2 compliance procedure.

Regulatory Order to Establish RACT SWCAA 95-1787 established a plant-wide annual average emission rate limit and total tonnage limit for SO_2 and specified compliance dates for achieving these emission limits. This Order was appealed by a third party to the Pollution Control Hearings Board (PCHB). SWCAA issued Order of Withdrawal SWCAA 96-1872 to withdraw SWCAA 95-1787 while pursuing additional SO_2 emission reductions through a collaborative process. However, the PCHB ruled SWCAA 96-1872 was an amendment to the original RACT Order, and therefore the RACT Order (95-1787) was still in effect. The SWCAA Board then approved Resolution 1996-8 on September 18, 1996 which withdrew both SWCAA 95-1787 and 96-1872, a decision later upheld by the PCHB.

An EPA Order on Consent was issued on May 18, 2001 to allow the permittee to commence construction of the Combustion Turbine Facility prior to issuance of a PSD permit. This order became obsolete upon issuance of PSD permit # PSD-01-01.

PSD-01-01 was issued on February 22, 2002 for construction of the Combustion Turbine Facility. This PSD permit dealt only with those PSD pollutants with emissions at or above the PSD significance threshold (PM and NO_X). SWCAA Air Discharge Permit 01-2350 was issued on May 30, 2001 to address emissions of all other pollutants. Air Discharge Permit 01-2350 was superseded by Air Discharge Permit SWCAA 01-2350R1, issued on May 6, 2002. Air Discharge Permit SWCAA 01-2350R1 was written in response to an Air Discharge Permit application requesting an increase in the combustion turbine facility's sulfur oxides emission limits.

The permittee became aware on July 12, 2002 that the auxiliary boiler that was ultimately installed at the Combustion Turbine Facility was not the one approved by PSD-01-01 or Air Discharge Permit SWCAA 01-2350R1. PSD-01-01 and Air Discharge Permit SWCAA 01-2350R1 approved the 4.18 MMBtu/hr Cleaver-Brooks boiler specified in the Notice of Construction (NOC) applications for those permits. The permittee notified SWCAA of this fact on the next business day (July 15, 2002).

On July 22, 2002 SWCAA issued Consent Order SWCAA 02-2422 to address the issue. The consent order was signed by Ms. Linda Chambers for TransAlta Centralia Generation, LLC on July 24, 2002. This consent Order became obsolete with the submittal of a Notice of Construction L-505 on August 15, 2002 (submittal of this notice satisfied the last requirement in the consent order).

PSD-01-01 was superseded by PSD-01-01 Amendment 1 on January 30, 2003. The permit amendment was made to approve the existing BHP Auxiliary Boiler.

Air Discharge Permit 01-2350R1 was superseded by Air Discharge Permit 01-2350R2 on October 15, 2003. Air Discharge Permit 01-2350R2 was written in response to Air Discharge Permit application L-505 for approval of the existing BHP Auxiliary Boiler.

PSD-01-01 Amendment 1 was superseded by PSD-01-01 Amendment 2 on June 11, 2004. The permit amendment was made to clarify the RATA frequency requirements.

Air Discharge Permit 01-2350R2 was superseded by Air Discharge Permit 01-2350R3 on May 12, 2005. Air Discharge Permit 01-2350R3 was written to make the source testing and RATA frequencies in the minor source permit consistent with the RATA frequencies in PSD-01-01 and the Acid Rain Program rules.

Air Discharge Permit 05-2612 was issued on July 15, 2005 for the addition of a coal unloading hopper to the West Coal Unloading Facility. Air Discharge Permit 05-2612 was superseded by Air Discharge Permit 07-2712 on February 7, 2007. Air Discharge Permit 07-2712 was written in response to a request for installation of surge capacity to the West Coal Unloading Facility. Air Discharge Permit 07-2712 was superseded by Air Discharge Permit 07-2749 on September 26, 2007. Air Discharge Permit 07-2749 was written in response to a request for modification of the West Coal Unloading Facility operating limitations and installation of the East Coal Unloading Facility.

Air Discharge Permit 01-2350R3 was superseded by Air Discharge Permit 01-2350R4 on January 18, 2008. Air Discharge Permit SWCAA 01-2350R4 was written in response to an ADP application submitted by the permittee to eliminate the 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) was retained.

2. Future MACT/NESHAP Standards

National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters 40 CFR Part 63.7480 et seq. Subpart DDDDD - [12/6/06]

The DC Circuit Court vacated the boiler MACT on June 8, 2007. A 45-day appeal window applied to the decision. The vacation order was signed July 30, 2007. When the USEPA misses the scheduled promulgation date for issuing a MACT standard, a case-by-case MACT determination must be made by the permitting authority ("MACT Hammer" provisions) for applicable units. To enable this determination, 40 CFR 63 Subpart B requires that the owner or operator of an applicable source submit an application to the Title V permitting authority containing the information in 40 CFR 63.53 no later than 18 months after the scheduled rule promulgation date. The circumstances that have occurred here, where the USEPA issued a MACT standard that was later vacated by the court, are not addressed in 40 CFR 63. It is not clear whether applicable sources will be required to submit these applications 18 months after the July 30, 2007 court vacature of the rule, or some other date. These requirements will not be clear until EPA decides how to implement the "MACT Hammer" in this case. Considering that the applicable units at this facility had no active requirements in Subpart DDDDD (the units were subject only to an initial notification requirement), are not significant sources of hazardous air pollutants, and further guidance or rulemaking by the USEPA is anticipated, SWCAA will take no action with regard to these units at this time.

The original boiler MACT had applied in the following manner:

Subpart DDDDD applies to industrial, commercial and institutional boilers and process heaters at major sources of HAP emissions. The regulation applies to the Auxiliary Boiler at the coal plant (EU-3), and the BHP Auxiliary Boiler in the combustion turbine facility (EU-12). EU-3 is in the "Limited Use Liquid Fuel" subcategory because fuel consumption is limited to 600,000 gallons per year (equivalent to an annual capacity factor of less than 6%). The "Limited Use Liquid Fuel" subcategory includes boilers with a rated capacity of 10 MMBtu/hr or greater that burn liquid fuel and have a federally enforceable annual average capacity factor of equal to or less than 10%. EU-12 is in the "Small Gaseous Fuel" subcategory because it is a firetube boiler that burns only natural gas. 40 CFR 63.7506(b)(2) states that for units in the "Limited Use Liquid Fuel" subcategory, the unit is subject only to the initial notification requirements of 40 CFR 63.9. No other requirements of 40 CFR 63 Subparts A or DDDDD apply to units in the "Limited Use Liquid Fuel" subcategory. 40 CFR 64.7506(c)(3) states that units in the "Small Gaseous Fuel" subcategory are not subject to any requirements in 40 CFR 63 Subparts A or DDDDD.

Initial notification of applicability was due no later than 120 days after publication of this requirement in the Federal Register. This requirement was published November 12, 2004, therefore the initial notification for applicable source was due no later than March 12, 2005. TransAlta submitted their notification in a letter dated September 30, 2004; therefore all requirements of this subpart have been satisfied.

National Emission Standards for Hazardous Air Pollutants – Mercury from Coal-Fired Electric Utility Steam Generating Units (Utility Units)

On December 20, 2000, pursuant to Clean Air Act (CAA) section 112(n)(1)(A), EPA determined that it was both appropriate and necessary to regulate coal fired Utility Units under section 112 of the CAA. For coal-fired Utility Units, mercury was the only HAP that EPA found that needed to be addressed. On January 30, 2004, EPA published a proposed MACT standard for mercury from coal-fired Utility Units, and an alternative NSPS for coal-fired Utility Units in the Federal Register. On March 29, 2005, prior to taking any final action on the proposed rule, EPA revised it's December 20, 2000 finding and concluded that it was neither appropriate nor necessary to regulate coal and oil-fired Utility Units under section 112 of the CAA.

On May 18, 2005, EPA issued "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" in the Federal Register. This set of rules was referred to as the Clean Air Mercury Rule (CAMR). This rule regulated mercury units under section 111 of the CAA by establishing a national cap and trade program for mercury from coal-fired Utility Units. This rule modified 40 CFR 60, 72, and 75.

On February 8, 2008 the United States Court of Appeals for the District of Columbia Circuit ruled that EPA's removal of coal-fired Utility Units from the list of sources to be regulated under section 112 of the CAA was unlawful. The court vacated the delisting and CAMR, remanding CAMR to EPA for reconsideration. In 2009 EPA decided to develop emissions standards for power plants under the Clean Air Act Section 112, consistent with the D.C. Circuit's opinion on CAMR. Accordingly, on February 6, 2009,

the Department of Justice, on behalf of EPA, asked the Supreme Court to dismiss EPA's request (petition for certiorari) that the Court review the D.C. Circuit Court's vacatur of CAMR.

National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines 40 CFR Part 63.6580 et seq. Subpart ZZZZ - [3/5/09]

This Rule establishes national emission limitations and operating limitations for HAP emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. Emergency Diesel Generator #1, Emergency Diesel Generator #2, Emergency Diesel Fire Pump, and the Black Stop Diesel Generator Engine are affected sources under this regulation; however per 40 CFR 63.6590(b)(3) existing stationary RICE are not subject to any requirements of this regulation, including initial notification.

For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if construction or reconstruction of the stationary RICE commenced before December 19, 2002. For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if construction or reconstruction of the stationary RICE commenced before June 12, 2006. Emergency Diesel Generator #1, Emergency Diesel Generator #2, Emergency Diesel Fire Pump, and the Black Stop Diesel Generator Engine all are existing compression ignition RICE for the purposes of this rule.

In a Federal Register Notice dated March 5, 2009, EPA proposed significant modifications to this regulation. One of the proposed modifications requires owners or operators of stationary emergency RICE located at major sources to operate and maintain their stationary RICE and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan. In addition, Emergency Generator #1, Emergency Generator #2, and the Emergency Diesel Fire Pump could be subject to CO emission limits and performance testing requirements.

3. Acid Rain Requirements

The general Acid Rain recordkeeping provisions of 40 CFR 75.50 are no longer valid as of January 1, 1996, and are replaced by the general recordkeeping provisions of 40 CFR 75.54. The Acid Rain Program provided an optional set of recordkeeping requirements with only slightly different provisions prior to January 1, 1996, but disallows their use from January 1996 onward.

4. Initial Testing Requirements for Combustion Turbines and Duct Burners

The initial testing requirements of 40 CFR 60.18 for the combustion turbines and the duct burners have all been completed with initial startup of the equipment in 2001.

5. Initial Testing Requirements for Limestone Ball Mill

The initial testing requirements of 40 CFR 60.18 for the Limestone Ball Mill (consisting of opacity observations as specified in 40 CFR 60 Subpart OOO) were completed on October 24, 2007.

6. Future Requirement - State-Only Greenhouse Gas Requirements – Applicable if Triggered

WAC 173-407 (effective July 20, 2008) establishes a greenhouse gas emission standard and attendant monitoring, recordkeeping, reporting and, if necessary, sequestration requirements. In accordance with WAC 173-407-120(3), the rule would apply to the Permittee's facility if:

(a) The facility or a unit is upgraded; or
(b) The existing facility or a unit is subject to a new long-term financial commitment.

An "upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility or unit.

A "long-term financial commitment means:

(a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or
(b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

"New ownership interest" means a change in the ownership structure of a baseload power plant or a cogeneration facility or the electrical generation portion of a cogeneration facility affecting at least:

(a) Five percent of the market value of the power plant or cogeneration facility; or
(b) Five percent of the electrical output of the power plant or cogeneration facility.
The above thresholds apply to each unit within a multi-unit generation facility.

7. Future Requirement - State-Only Greenhouse Gas Reporting Requirements

In 2008 the Washington State Legislature passed, and the governor signed, Engrossed Second Substitute House Bill 2815, Greenhouse Gas Emissions. E2SHB requires large stationary sources of greenhouse gas emissions to beginning reporting greenhouse gas emissions beginning in 2010 for calendar year 2009 emissions. The bill modified RCW 70.94.151 to require the Washington Department of Ecology to adopt rules requiring reporting of greenhouse gas emissions. The Washington Department of Ecology filed a CR-101 "Preproposal Statement of Inquiry" on July 23, 2008 to adopt the rules implementing the greenhouse gas reporting requirements of E2SHB 2815 and RCW 70.94. The new rules will be codified in WAC 173-441 "Reporting of Emissions of Greenhouse Gases."

8. Future Requirement - Federal Greenhouse Gas Reporting Requirements

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110–161), EPA has proposed a rule that requires mandatory reporting of greenhouse gas (GHG) emissions from large sources in the United States. The proposed rule would collect accurate and comprehensive emissions data to inform future policy decisions. The proposed rule was signed by the Administrator on March 10, 2009. On April 10, 2009 the proposed rule was published in the Federal Register. EPA is proposing that reporters would be required to submit their first GHG emissions report to EPA in early 2011. This report would provide data on emissions from the year 2010.

9. Future Requirement – Best Available Retrofit Technology (BART) Emission Limits

40 CFR 51 Subpart P requires states to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution. This section applies to existing stationary facilities as defined in 40 CFR 51.301. The definition of "existing stationary facilities" includes fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input that was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant and is in one of the source categories listed in 40 CFR 51.301. EU-1 and EU-2 are affected by this regulation.

WAC 173-151 and SWCAA 400-151 require Ecology and SWCAA respectively to determine BART for eligible facilities, and requires those facilities to apply BART. In a Federal Register notice dated June 11, 2003, EPA concluded that the RACT Order 97-2057R1 limitations for PM and SO_2 represent BART. EPA went on to say "Additionally, while the NO_X emission limitation may have represented BART when the emission limits in the RACT Order were negotiated, recent technology advancements have been made. EPA cannot now say that the emission limitations in the (SWCAA) RACT Order for NO_X represent BART."

The Washington Department of Ecology has taken the lead role in determining BART for EU-1 and EU-2. The Washington Department of Ecology is expected to issue a BART Order in 2009 that establishes BART for NO_X emissions from EU-1 and EU-2. It should be noted that the Permittee has argued that all BART requirements (including those for NO_X) were satisfied by RACT Order 97-2057R1.

10. Future Requirement – State-Only Mercury Emission Limits for EU-1 and EU-2

In the fall of 2007 the Permittee and the Washington Department of Ecology began a mediation process to discuss a number of environmental issues in the hopes of resolving these issues without resorting to litigation. In a meeting on March 31, 2009 to discuss the mediation agreement with the public, Washington State Department of Ecology announced that the Permittee had voluntarily agreed to install mercury emission controls to target a mercury reduction of 50% from the facility. If such an agreement is finalized, the Permittee would be subject to new requirements related to mercury control.

VII. EXPLANATION OF MONITORING TERMS AND CONDITIONS

M1. Visible Emission Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400 and the specific requirements drawn from PSD-01-01 Amendment 2, SWCAA 97-2057R1, SWCAA 01-2403, and SWCAA 01-2350R4. The general requirements in WAC 173-400 and SWCAA 400 do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M1 is designed to provide periodic assurance of compliance, and record any necessary corrective action. This requirement pertains to the visual technique for evaluating visible emissions, not the continuous monitor method. Demonstration of compliance is required in some cases via visible emissions evaluation. An individual educated in the procedures of visible emission observation and evaluation is to perform the periodic compliance assurance monitoring. A Certified Observer, certified in accordance with EPA Method 9, is to perform the visible emission observations based on the method in Appendix A of the Air Operating Permit.

M2. Particulate Matter Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400. A particulate matter exhaust standard of 0.1 gr/dscf applies to both combustion and non-combustion emission units. These requirements do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M2 is designed to assure compliance through periodic facility inspections and prompt corrective action within 2 hours of observing particulate matter fallout or excess visible emissions whenever necessary. The permittee is required to resolve the particulate matter fallout or excess emissions problem within 24 hours of initial discovery, or notify SWCAA by the next working day of progress made towards resolution. Excess emissions are emissions above the state standard or permit limit. The site inspection and visual observation are surrogate methods for assessing the relative emissions from non-combustion emission units EU-4, EU-5, and EU-6 that have demonstrated emissions well below the general standards.

Both Coal Plant units (EU-1 and EU-2) are equipped with electrostatic precipitators that remove over 99.5% of the particulate matter from coal combustion leaving emission concentrations less than one-tenth of the standard in Req-9. Combustion of fuel oil in the auxiliary boiler (EU-3) does not produce emission concentrations near this standard either. Monitoring for the standards in Reqs-9 and 11 makes use of observations that will readily indicate if control equipment or material handling management practices are seriously

deficient. The site inspection and visual observation are surrogate methods for assessing the relative emissions from emission units EU-1, EU-2, and EU-3 that have demonstrated emissions well below the general standards.

Condition 2 of Air Discharge Permit SWCAA 07-2749 requires that the water pressure of the spray/fog nozzles be maintained at 80 psig or greater during operation of the coal unloading facilities, however no monitoring of the water pressure was required (although a visual inspection is required monthly). Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 that require the spray pressure to be measured during the monthly inspection and recoded in accordance with Section VIII K1(a).

M3. Fugitive Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400 and the specific requirement from SWCAA 01-2403 to control fugitive dust from operation of the fly ash pugmill. WAC 173-400 and SWCAA 400 do not directly establish any specific regime of monitoring or recordkeeping for these standards. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 for those general requirements. M3 is designed to assure compliance through a combination of periodic facility inspections, use of reasonable precautions and good work practices, and prompt corrective action whenever necessary.

M4. Complaint Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400 and the specific requirement in SWCAA 01-2350R4 (nuisance odors). These requirements do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. M4 is designed to assure compliance through prompt complaint response and corrective action whenever necessary.

M5. Operations Monitoring

The requirements cited in this monitoring section are "gap-filling" monitoring under the authority of WAC 173-401-615(1). No requirements rely solely on this monitoring condition to assure compliance. These requirements ensure sufficient monitoring where the applicable rule or permit does not provide an adequate assurance of compliance with the applicable requirement. M5 is designed to assure compliance through operation of pollution control equipment according to manufacturer specifications and/or consistent with good engineering and maintenance practices, and by taking corrective action whenever necessary. Emissions control equipment is operated to minimize overall long-term emissions. Manufacturer specifications should be followed except in instances where alternative practices are equivalent or better. The goal is to maintain performance rather than follow exact manufacturer specifications.

M6. Coal Plant SO_2 General Standard Monitoring

This monitoring requirement in combination with M9 is used to provide a reasonable assurance of compliance with the general SO_2 emission concentration limit contained in WAC 173-400 and SWCAA 400. WAC 173-400-040(6) and SWCAA 400-040(6) limit the emission of sulfur dioxide from combustion sources to a maximum of 1,000 ppmv corrected to a specified oxygen percentage as noted in SWCAA 400-050(3). The combustion sources at this facility combust pulverized coal and fuel oil (#2 distillate diesel oil). EU-3 is fueled exclusively with fuel oil, and its monitoring requirement consists only of quarterly certification of fuel sulfur content. A CEM mandated by the Acid Rain Program continuously measures the SO_2 concentrations of the flue gasses emitted by EU-1 and EU-2 and determines 60-minute averages (see M9).

SWCAA 97-2057R1 requires the use of coal sulfur content sampling to fill in missing CEM data periods, and certification of fuel oil burned in the auxiliary boiler and BW21 and BW22, but does not detail the frequency of such monitoring. This requirement provides the explanation of the minimum monitoring necessary to comply with these requirements. Monitoring of coal sulfur content by monthly composite sampling is required for comparison and potential backup purposes in the event of missing CEMS data. The conversion between fuel sulfur content and SO_2 concentration relies upon an approximate linear relationship based on operational experience with a coal sulfur content of 1% by weight corresponding to an SO_2 bypass stack concentration of 1,000 ppm. Quarterly certification of fuel oil sulfur content is required to demonstrate compliance with the 1,000 ppm requirement, but the frequency of each sulfur content determination depends on the fuel suppliers' shipments and is not a continuous monitoring requirement. The maximum level of sulfur in the fuel oil consumed is 0.5% by weight. The following calculation demonstrates how the 1,000 ppmvd sulfur dioxide limit cannot be exceeded when burning fuel oil with a sulfur content of 0.5% or less:

$$\text{ppm}\,SO_2 @ 7\%\,O_2 = \frac{7.206\,\text{lb oil}}{\text{gallon}} \bullet \frac{1\,\text{gallon}}{0.141\,\text{MMBtu}} \bullet \frac{0.005\,\text{lb S}}{\text{lb oil}} \bullet \frac{\text{lb} \cdot \text{mole}}{32\,\text{lb S}} \bullet \frac{385\,\text{scf}}{\text{lb} \cdot \text{mole}} \bullet \frac{\text{MMBtu}}{9{,}190\,\text{dscf}} \bullet \frac{(20.9 - 7\%O_2)}{20.9} \bullet 10^6$$

$$\text{ppm}\,SO_2 @ 7\%\,O_2 = 222$$

M7. Coal Plant Stack Sampling Monitoring Requirements

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400 and the specific emission limits contained in SWCAA 97-2057R1. SWCAA 400-052 specifies a frequency for source testing of all applicable combustion units, which are those which emit 100 tons per year or more of NO_X, CO, particulate matter, SO_2, or VOC. Emissions tests are required every two calendar years for those pollutants for which the source emits 100 tons per year or more. The use of continuous emissions monitors is an acceptable alternative to the specified sampling schedule. The permittee operates CEMS at each stack for NO_X and SO_2 that meet Acid Rain requirements. In addition, CO is continuously monitored from both scrubbed flues. Requirement M8 is designed to elaborate on the SWCAA-only regulation, integrate its requirements with those from the RACT Order, and provide periodic assurance of compliance with the particulate matter exhaust concentration standards.

Past source testing at the bypass stacks has indicated compliance with the particulate matter emission limits by a wide margin. Several source tests have been conducted on scrubbed flues to date, and as expected, PM emissions from the scrubbed flue were extremely low (near the detection limit of a 1-hour PM sample). Because continuous methods are used to quantify emissions of SO_2, NO_X, and CO, compliance with the PM emission limits has been repeatedly demonstrated by a wide margin, and because opacity monitor data and equipment maintenance review provides additional assurance that PM emission limits are met, periodic source testing is adequate to provide a reasonable assurance of continuous compliance with the PM emission limit.

M8. Coal Plant General Continuous Monitoring Provisions

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from WAC 173-400 and SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, and provide compliance with the Acid Rain requirements.

A CEMS for SO_2, NO_X, CO, and CO_2 will monitor exhaust concentrations and mass emission rates of these pollutants from the coal-fired boilers. A COMS for measuring the opacity of emissions will be retained at each bypass stack, but will not be installed on the scrubber flues because condensed water vapor makes opacity monitoring at these flues impossible. SWCAA 97-2057R1 requires the use of an SO_2/O_2 CEMS on the bypass stacks. NO_X and CO_2 CEMS are not required on the bypass stacks by SWCAA 97-2057R1, local, state, or federal (40 CFR 75) regulations. The CEMS and/or COMS are calibrated daily in the active stack to ensure accurate measurements. An O_2 monitor measures and records O_2 concentration in the stack gas discharged to the atmosphere consistent with the Acid Rain monitoring provisions, although the requirement for operating an O_2 monitor is based on SWCAA 97-2057R1, Sections 21 and 27a, WAC 173-400-040(6) and 173-400-050(3), and SWCAA 400-040(6) and 400-050(3) which specify the 1-hour average SO_2 concentration data be on a dry basis corrected to 7% O_2. The correction method uses the as-measured SO_2

concentration for each clock hour and the corresponding actual O_2 concentration to standardize the SO_2 data to 7% O_2, as shown:

SO_2, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * SO_2, dry @ actual O_2%

This monitoring is to be used for demonstrating compliance with the specific pollutant emissions limits and standards in the permit. The monitors are to be installed, operated, maintained, and calibrated in accordance with the Acid Rain Program monitoring requirements, including procedures for missing data substitution. WAC 173-400-040(1) does not directly establish any specific regime of continuous monitoring or recordkeeping with the COMS. Consequently, SWCAA has used the monitoring requirements from SWCAA 97-2057R1 Section 36 and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. Requirement M9(d) is designed to assure compliance with the state visible emissions standard using the COMS 6-minute average opacity data. Monitoring of 1-minute average opacity also meets this monitoring requirement because 6-minute averages may be calculated from 1-minute average data. This method of evaluation is deemed adequate to demonstrate compliance with the visible emissions standard of WAC 173-400-040(1) and SWCAA 400-040(1), which is primarily a visual observation method. SWCAA 97-2057R1 Section 36 specifies that evaluation of the visible emission standard occur by both COMS and visual observation using Method 9 as prescribed in Appendix A to the permit.

Missing data procedures for the Acid Rain Program are specified for those hours when the CEMS does not measure or record valid data for the applicable monitors. The requirements specify methods for substituting data depending on factors such as the length of the missing data period and monitor system data availability rate. For compliance with the SO_2 concentration standard of WAC 173-400-040(6) and SWCAA 400-040(6), the missing data procedures are identical to those of 40 CFR 75.30 - 75.33 when the length of the missing data period is four hours or less. However, when monitor out-of-service periods are greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the permittee, and plant operating data is evaluated. For SWCAA, the purpose of missing data substitution is to represent true and actual emissions as closely as possible. Therefore, the data or combination of data that best represents actual emissions is used to determine the SO_2 concentrations.

M9. Coal Plant Startup, Shut Down, and Outage Operation Procedures

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Pursuant to SWCAA 400-081 "Start-up and Shutdown," technology based emission standards and control technology determinations shall take into consideration the physical and operational ability of a source to comply with the applicable standards during start-up or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during start-up or shutdown, SWCAA shall include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during start-up or shutdown.

M10 ensures sufficient monitoring to excuse unavoidable excess emissions or demonstrate compliance with the permit. The use of terms, test methods, units, averaging periods, and other conventions will be consistent with the applicable requirements. Emissions control equipment is operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance.

Exceedances of the PM and opacity limitations are excused under SWCAA 97-2057R1 based on WAC 173-400-107 and SWCAA 400-107 during on-line preventive maintenance and manual ESP rapping which may cause short duration emissions increases, and during startup and shutdown when the ESPs are out of service. Excess emissions due to scheduled maintenance are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been avoided through reasonable design, better scheduling for maintenance, or through better operation and maintenance practices. ESP component maintenance and manual rapping of ESP plates are among the maintenance activities that often result in short duration excess emissions, however these excess emissions are considered unavoidable and necessary to enhance long-term equipment performance and, as such, are excused from penalty.

Shutdown of one FGD system requires opening of the damper to the associated bypass stack. This operation has been known to cause excess opacity. The cause of the excess opacity is believed to be re-entrainment of ash deposited in the duct near the damper. Excess opacity due to opening of the bypass damper and re-entrainment of ash deposits is unavoidable, and therefore will be excused from penalty providing:

(a) The permittee reports the excess emission as soon as possible but no later than 48 hours after discovery;
(b) The permittee adequately demonstrates that the cause of the excess opacity was opening of the bypass duct (e.g. the excess opacity was contemporaneous with bypass duct opening); and
(c) The permittee adequately demonstrates that directing flue gas to the bypass stack was unavoidable (e.g. the FGD shutdown was not reasonably preventable).

Hourly SO_2 emissions during shutdown, startup, and maintenance of the SO_2 emission control technology in excess of 250 ppm are excused under WAC 173-400-107 and SWCAA 400-107 provided the alternative hourly SO_2 limits of Req-20 are not exceeded. Shutdown and startup periods are defined based on an ESP temperature of 220°F or below, and the startup period begins when fuel is introduced into a boiler to raise its temperature to operating conditions. ESP operation during startup and shutdown of EU-1 or EU-2 will degrade the overall ESP performance. When ESP temperature is below about 220°F, and especially when the boiler is combusting fuel oil, continued operation can result in fouling of the precipitator plates, which decreases long-term PM collection efficiency. Operation of the SO_2 emission control technology when the ESPs are off line and not removing PM is expected to foul or possibly plug key components, so the SO_2 emission control technology is not required to be placed in operation until the upstream ESPs are functioning. The end of the startup period is defined based on identifiable operating events.

Emissions in excess of both the 250 ppm hourly SO_2 limit and the alternative shutdown, startup, and SO_2 emission control technology outage limits of Req-20 may be excused provided the permittee meets the burden of proof regarding unavoidable emissions under

WAC 173-400-107 and SWCAA 400-107, especially subsections (4), (5), and (6). For unit startups, shutdowns, and on-line maintenance when the SO_2 emission control technology is out of service, the permittee is expected to blend lower sulfur coal into the boiler fuel supply prior to a planned outage of the SO_2 control system. The permittee submitted a scrubber startup, shutdown, and maintenance procedure in correspondence dated September 19, 2002. The document outlines the procedures implemented by the permittee to maintain compliance with the emission limits and operational requirements imposed by applicable air regulations and permits.

Sulfur dioxide emissions in excess of the 1,000 ppm limit in Req-20 are unavoidable during the first 6 – 8 hours (the length of time required to burn through coal stored in the silos) of a forced outage of the flue gas desulfurization (FGD) system if the cause of the forced outage is itself unavoidable. Good air pollution control practice for minimizing emissions during a forced outage of the FGD system include changing the coal blend so that emissions will be reduced below the 1,000 ppm limit after the high-sulfur coal blend is burned out of the silos. The permittee has indicated that the coal blend will be changed within approximately 15 minutes of notification of a scrubber problem.

M10. Coal Plant SO_2 12-Month Period Emission Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Calculation of the annual tons of SO_2 emitted for comparison with the limitations shall include all hourly SO_2 emission data, including startups, shutdowns, upsets, and forced or planned emission control system outages. An exceedance of the annual limitation is defined as any consecutive 12 calendar months in which SO_2 emissions exceed the tons per year SO_2 limitations applicable at the time. Although each day in the last month of the 12-month exceedance period can be treated as a separate day of violation, an alternative day-by-day evaluation method can be used by the permittee to more specifically identify the violation period. According to the alternative evaluation method, the number of violation days is equal to the number of 365-day emission summations, ending within the last month of the exceedance period, in which the SO_2 emissions exceed the annual limitation. This alternative evaluation method is the same as a 365-day rolling total, rolled each calendar day.

M11. Coal Plant Selected SO_2 Emission Control Configuration

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. The owners of the Centralia Plant had sole discretion to select the SO_2 emission control technology provided it met the SO_2 emission requirements specified in Requirements 16 and 19. In addition, the Centralia Plant owners had sole discretion to select the NO_X emission control technology provided it satisfied Requirements 25 and 26 (Req-26 contained an interim NO_X emission limit). The control technology configuration could include the maintenance of the original stacks for bypass provided a CEMS was maintained to monitor SO_2 emissions from the bypass stacks.

If the bypass stacks do not contain certified functional CEMS for SO_2, any emergency bypass emissions released through these stacks will be considered an upset condition reportable to SWCAA as a deviation from permit conditions. All SO_2 emissions released from the facility, regardless of where, how, or under what operating condition, is included in the plant SO_2 total for comparison with the annual limitation.

M12. Coal Plant Fuel Oil Usage Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. The permittee is required to monitor fuel oil usage in all of the boilers. The permittee accepted a voluntary limit on the amount of fuel oil consumed by the auxiliary boiler (EU-3) so it would not be necessary to evaluate RACT for this unit. RACT may have otherwise been applicable because the auxiliary boiler's potential-to-emit was sufficient to qualify it as a major source on its own, even though emissions calculated from actual fuel usage resulted in emissions substantially below the major source threshold. To evaluate fuel usage compared to the consumption limit, the auxiliary boiler must be equipped with a separate fuel meter or be supplied by its own unique fuel tank to identify fuel consumed in the auxiliary boiler. If the auxiliary boiler consumes fuel oil containing the maximum allowed 0.5% sulfur by weight, the SO_2 emissions from EU-3 will be larger than emissions of other criteria pollutants from EU-3. Emissions are calculated based on emission factors from U.S. EPA AP-42 §1.3. An example of this SO_2 emission calculation using the maximum allowed annual fuel consumption is shown below:
600,000 gallon/yr * (144)(0.5) lb/1000 gallon * (1 ton/2,000 lb) = 21.6 tons per year

M13. Combustion Turbine Facility Continuous Emission Monitoring Requirements

This monitoring requirement is used to provide, in combination with other monitoring requirements, a reasonable assurance of compliance with the NO_X limitations contained in 40 CFR 60.44b and the specific emission limits contained in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. In addition, it provides compliance with the Acid Rain monitoring requirements. The use of CEMS to measure NO_X, CO, and NH_3 emissions from the turbines is presumptively sufficient to demonstrate continuous compliance with the turbine emission limits for those pollutants. Because the vast majority of NO_X and CO emissions will come from the turbines, and because periodic source testing will be conducted to quantify NO_X and CO emissions from the black stop diesel generator and BHP Auxiliary Boiler (which are likely to have relatively consistent emissions), this monitoring requirement, in conjunction with periodic source testing, is adequate to provide a reasonable assurance of compliance with the plantwide NO_X and CO emission limits.

Ammonia emissions are currently monitored on a wet basis. The performance specifications listed in M13 are performance based and are not prescriptive as to whether a wet or dry CEMS is installed. Concentration based emission limits for the combustion turbines are expressed on a dry basis. To convert the monitored wet concentration to a dry concentration for reporting and comparison with permitted emission limits, the permittee may monitor moisture content directly, apply a default moisture correction

factor based on past source emissions testing, or calculate stack gas moisture content using a mass balance approach accounting for moisture from combustion and water injection into the turbine. Regardless of the approach that is used, the CEMS output when corrected to a dry basis must be capable of meeting the relevant relative accuracy specifications.

The requirements to monitor differential pressures across each catalyst bed, and flue gas temperature upstream and downstream of each catalyst bed were included to provide SWCAA with data valuable for future permitting actions. The pressure drop across a catalyst bed is directly related to the fuel cost of installing a catalyst bed. The temperatures indicate whether the proper operating temperatures are being achieved and help identify which catalyst technology is appropriate for future installations.

M14. Combustion Turbine Facility Source Testing Requirements

This monitoring requirement is used to provide, in combination with other monitoring requirements, a reasonable assurance of compliance with the NO_X limitations contained in 40 CFR 60.44b and the specific emission limits contained in SWCAA 01-2350R4 and PSD-01-01 Amendment 2.

Each combustion turbine is tested at least once for every four operating quarters or eight calendar quarters, whichever comes first to quantify emissions of NO_X, CO, PM, NH_3, and VOCs. When testing is not convenient or possible within the fourth operating quarter or the eighth calendar quarter, testing may be conducted no later than the end of a 720 hour "grace period" following the end of the quarter. For the purposes of determining when a subsequent test is due, the end of the fourth operating quarter or eighth calendar quarter is used, not the date of a test conducted after the end of the fourth operating quarter or eighth calendar quarter and within the 720 hour "grace period." In this way, testing will be conducted at least once for every four operating quarters or eight calendar quarters. PSD-01-01 Amendment 2 requires that the black stop diesel generator and BHP Auxiliary Boiler be tested every two years or 500 hours of operation, whichever is least frequent. Air Discharge Permit SWCAA 01-2350R4 requires testing of the BHP Auxiliary Boiler at least once every 2 years. NO_X, CO, and NH_3 emissions from the combustion turbines are monitored continuously with a CEM. The periodic combustion turbine source tests provide an additional level of quality assurance for the CEM data. The combustion of natural gas is not likely to generate particulate matter emissions approaching the emission limits. The combustion turbine PM emission limits were set based on conservative vendor guarantees. Based on past experience with similar combustion turbines, and considering the fact that an oxidation catalyst is installed to control CO and VOC emissions, VOC emissions are expected to be consistent and minimal, therefore annual source testing will provide an adequate assurance of continuous compliance.

The black stop diesel generator and BHP Auxiliary Boiler are not equipped with add-on controls. Uncontrolled emissions from diesel engines, and especially package boilers, are relatively consistent, therefore testing every two years or 500 hours of operation will provide an adequate assurance of continuous compliance with the applicable emission limits. Any maintenance activities that may affect emissions must be documented (M23). In addition, it is likely that the black stop diesel generator will be operated less than 50 hours per year.

M15. Combustion Turbine Facility Startup, Shut Down, and Outage Operation Procedures

This monitoring requirement is used to provide, in combination with other monitoring requirements, a reasonable assurance of compliance with the NO_X limitations contained in 40 CFR 60.44b and the specific emission limits contained in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. Pursuant to WAC 400-081 and SWCAA 400-081 "Start-up and Shutdown," technology based emission standards and control technology determinations shall take into consideration the physical and operational ability of a source to comply with the applicable standards during startup or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during startup or shutdown, SWCAA must include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during startup or shutdown.

The startup and shutdown provisions for the combustion turbines were written to satisfy these requirements. SWCAA determined that the emission limits, (primarily NO_X and CO limits), cannot be met during startup when uncontrolled emission concentrations are significantly higher than during normal operation, and emission control systems are not yet operating.

In addition, it is likely that opacity from the Black Stop Diesel Generator Engine will exceed 10% during the first few minutes after startup (until the engine warms sufficiently).

M16. Combustion Turbine Facility SO_2 General Standard Monitoring

This monitoring requirement is used to provide, in combination with fuel flow monitoring requirements, a reasonable assurance of compliance with the hourly and annual SO_2 emission limits contained in SWCAA 01-2350R4. In addition, M17 provides compliance with the Acid Rain and NSPS Subpart GG monitoring requirements. SO_2 emission concentrations can be calculated directly from the sulfur content of the natural gas combusted. When the amount of fuel combusted is also known, total sulfur emissions, expressed as SO_2 can be calculated using a mass balance approach.

$$SO_2\ (\text{lb/hr}) = (\text{fuel flow (lb/hr)}) \bullet (\text{fuel S concentration (weight fraction)}) \bullet \left(\frac{64\ \text{lb}\ SO_2}{32\ \text{lb S}} \right)$$

The permittee must combust natural gas containing greater than 5.0 gr total sulfur/100 scf at full load to exceed the hourly emission limit. The maximum Federal Energy Regulatory Commission (FERC) tariff for natural gas entering this region is 5.0 gr total sulfur/100scf, and typical sulfur concentrations are less than 1.0 gr/100scf, therefore a violation of the hourly emission limit is extremely unlikely. It is for these reasons that monitoring sulfur content semi-annually or whenever the source of the natural gas changes provides a reasonable assurance of continuous compliance.

40 CFR 60 Subpart GG was modified effective July 8, 2004. The modified rule stated that natural gas fired sources were no longer required to monitor for fuel sulfur content, even if fuel sulfur monitoring was required by an alternative fuel monitoring schedule. Both WAC 173-460-115 and SWCAA 400-115 have adopted this new version of Subpart GG.

Therefore the Permittee is no longer required to follow the Alternative Fuel Monitoring Schedule issued by EPA on November 13, 2001.

M17. Combustion Turbine NO_X Control System Testing

This monitoring requirement is used to provide, in combination with continuous NO_X and NH_3 emissions monitoring, a reasonable assurance of compliance with the requirement in SWCAA 01-2350R4 to control NO_X emissions to the greatest extent possible without generating excessive "ammonia slip." Continuous monitoring will alert the permittee and SWCAA to any changes in control system capability. Changes in control system capability (primarily due to catalyst degradation and fouling) occur slowly over a period of years; therefore testing of system capability need only be conducted annually. Each year the capability of the system is tested using the procedure described in M18 to quantify any changes in system capability. If reduced NO_X emissions can be achieved without generating excessive ammonia slip, then good air pollution control practices require that the control system be operated to target the reduced NO_X concentration.

M18. Ammonia Certification

This monitoring requirement is used to provide a reasonable assurance that the permittee stores only aqueous ammonia with a concentration of less than 20% by weight. By assuring that the concentration of each shipment is less than 20%, compliance with this requirement is continuously assured.

M19. Black Stop Diesel Generator Engine Fuel Certification

This monitoring requirement is used to provide a reasonable assurance that only fuel with a sulfur content of 0.05% or less is burned in the black stop diesel generator engine. Condition 14 of SWCAA 01-2350R4 specified that a fuel certification from the fuel supplier could be used to demonstrate compliance with the fuel sulfur content limitation because such certification is based on an analysis of the fuel. This monitoring requirement applies to each fuel shipment, therefore a fuel certification or fuel analysis must be provided for each fuel shipment.

M20. Black Stop Diesel Generator Engine Hours Monitoring

The data provided by this monitoring requirement is used to provide a reasonable assurance that the permittee operates the black stop diesel generator engine no more than 500 hours in any 12 months, and enable the calculation of annual (12-month rolling total) emissions. By recording the hours of operation monthly, compliance with the annual hours restriction and emission limits is continuously assured (a violation would be noted the first month). Emissions of CO, NO_X, and PM will be calculated using the hourly emission factors from the most recent source test. Emissions of VOCs and SO_2 will be calculated using the emission factors in the table below. All emission factors conservatively assume that the generator is operating at full load whenever it is in operation.

The following table details how emissions will be calculated to demonstrate compliance with the emission limits and report emissions for inventory purposes.

Pollutant	Hourly	Annual
Carbon monoxide	source test	source test data (lb/hr) multiplied by hours/year
Nitrogen oxides	source test	source test data (lb/hr) multiplied by hours/year
$PM/PM_{10}/PM_{2.5}$	source test	source test data (lb/hr) multiplied by hours/year
Volatile organic compounds	1.3 lb/hr	1.3 lb/hr multiplied by hours/year
Sulfur dioxide	0.52 lb/hr	0.52 lb/hr multiplied by hours/year

The emission factors for VOCs shall be replaced by source test data if a source test is conducted to quantify VOC emissions. The emission factor for sulfur dioxide may be replaced by a mass balance if the total amount of fuel consumed and the total sulfur content of the fuel is known.

M21. BHP Auxiliary Boiler Fuel Consumption

The data provided by this monitoring requirement is used to calculate annual emissions, including emissions of PM to demonstrate on-going compliance with the 0.7 ton per year (12-month rolling total) emission limit. Emissions of CO, NO_X, and PM will be calculated using emission factors (in units of lb/MMscf) from the most recent source test. Emissions of SO_2 will be calculated using a mass balance approach with the fuel flow data collected pursuant to M22, and the fuel sulfur data collected with M17. The emission factor for VOCs shall be replaced by source test data if a source test is conducted to quantify VOC emissions.

The following table details how emissions will be calculated to demonstrate compliance with the emission limits and report emissions for inventory purposes.

Pollutant	Hourly	Annual
Carbon monoxide	source test	source test data (lb/MMscf) multiplied by MMscf/yr
Nitrogen oxides	source test	source test data (lb/MMscf) multiplied by MMscf/yr
$PM/PM_{10}/PM_{2.5}$	source test	source test data (lb/MMscf) multiplied by MMscf/yr
VOCs	5.5 lb/MMscf multiplied by fuel consumption	
Sulfur dioxide	mass balance	mass balance (fuel sulfur content * by fuel use)

M22. Maintenance Activities Monitoring

The data provided by this monitoring requirement, in conjunction with source testing, provides a reasonable assurance that emissions that are not monitored continuously are within permitted limits. Each occurrence of maintenance and repairs to the fly ash unloading pugmill, turbine lube oil mist eliminators, combustion turbines, BHP Auxiliary Boiler, or Black Stop Diesel Generator Engine that may affect emissions is recorded. This data is available to plant personnel and SWCAA upon inspection. This data can be periodically reviewed by SWCAA and plant personnel to determine if emission factors used to calculate emissions remain valid.

For example, maintenance preformed on the burners of the BHP Auxiliary Boiler could affect emissions from the boiler and therefore a record must be made of this maintenance. Or, the replacement of filters in the lube oil mist eliminators could affect emissions if a slightly different filter were installed, therefore filter replacements for the turbine lube oil mist eliminators must be documented.

In general, this requirement is not necessary to provide a reasonable assurance of compliance with permitted limits. This monitoring term was included in SWCAA 01-2403 and SWCAA 01-2350R4 because it can be a valuable inspection tool that requires minimal effort on the part of the permittee.

M23. Particulate Matter Compliance Assurance Monitoring for BW21 and BW22

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-1 and EU-2 in accordance with 40 CFR 64 for the permit renewal. CAM is applicable to emissions from both the bypass and FGD stacks of EU-1 and EU-2. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes opacity as a surrogate indicator of particulate matter control device operation and particulate matter emissions.

The CAM plan for the bypass stacks was required because the permittee is allowed to use the bypass stack for limited periods of time outside of startup, shutdown, and extreme emergency conditions. To date, the bypass stacks have not been used except during startup and shutdown. Because facilitywide SO_2 emissions are limited to 10,000 tons per year, use of the unscrubbed bypass stacks rapidly utilizes the allowable annual emissions (at a rate of ~5 tons per hour per stack), therefore use of these stacks outside of startup, shutdown, and extreme emergencies is unlikely. Any significant use of the bypass stacks can result in restrictions on plant operation to maintain compliance with the 10,000 ton per year SO_2 limit.

For the FGD stacks, opacity in the ductwork upstream of the scrubber of less than 30% provides an adequate assurance that particulate matter emissions from the applicable FGD stack will be less than the permit limit. Source testing at this facility has demonstrated that the scrubbers are highly efficient at removing particulate matter from the flue gas. Particulate matter emission levels well below the indicator range will adversely affect scrubbing liquor chemistry and gypsum quality and potentially result in damage to the scrubber, therefore the permittee is highly motivated to maintain opacity levels well below the 30% level.

M24. Coal Unloading Facilities

The data provided by this monitoring requirement is used to calculate annual emissions of particulate matter from the coal unloading facilities.

M25. FGD Bleed Treatment Lime Storage Silo

Differential pressure across the dust collector must be recorded at least monthly to assist in evaluating whether the dust collector is operating properly. Large changes in

differential pressure can indicate operational problems. The number of hours the silo is actively vented must be recorded annually to allow the calculation of emissions from the silo. In conjunction with the monthly inspection required by M2, this data will provide a reasonable assurance of ongoing compliance with the particulate matter emission limits.

M26. Journal Shop

The amount of each type of welding rod that is used in the Journal Shop must be monitored and recorded to calculate annual emissions. The Journal Shop baghouse is designed to provide a high level of control and utilizes both primary filters and secondary HEPA filters. SWCAA believes that unless there is an obvious upset condition (for which monitoring is required), the unit will comply with particulate matter emission limits.

VIII. EXPLANATION OF RECORDKEEPING TERMS AND CONDITIONS

K1. Basic Recordkeeping

This recordkeeping section is taken directly from SWCAA 97-2057R2 Sections 26 and 29 and WAC 173-401-615(2). Sections (a) through (d) were added to clarify specific requirements. Under K1(c)(i) of the permit "equipment out of service" is limited to SO_2 emission control equipment, and "upset conditions" are limited to pollution control equipment or equipment that would directly impact SO_2 emissions.

K2. Continuous Emission Data Recordkeeping Requirements

This recordkeeping section is taken from 40 CFR 75.57, 75.58, and 75.59 and supplemented by specific requirements from SWCAA 97-2057R1, Sections 27 and 30 and the "gap filling" provisions of WAC 173-401-615(2).

The Acid Rain Program requires that pertinent records be maintained for at least three years from the date of the record. However, the recordkeeping provisions of the Air Operating Permit regulations, WAC 173-401-615(2)(c), require retention of records for a period of five years.

The basis for recordkeeping requirements for 1-hour SO_2 standard concentrations (dry @ 7% O_2) is the "gap filling" provisions of WAC 173-401-615(2). Data from the plant computer system not required by the Acid Rain Program is not saved for archiving in the same way that data consistent with 40 CFR 75.57 - 75.59 is recorded.

This recordkeeping section is taken from 40 CFR 75, SWCAA 97-2057R1, Sections 24, 26, and 27, and the "gap filling" provisions of WAC 173-401-615(2). The Acid Rain regulation specifies the type and format of data to be recorded for flow and SO_2 emissions from Acid Rain affected units. The data recordkeeping requirements pursuant to SWCAA 97-2057R1 for 1-hour SO_2 standard concentration (dry @ 7% O_2) are parallel to those of the Acid Rain Program, but for a smaller quantity of required data. The data recordkeeping requirements

for rolling 12-month SO_2 emissions (tons per year) are specified, and the additional data to be included in this summation stated for recordkeeping purposes.

The data recordkeeping requirements for hourly NO_X corresponding to unit generating load of 360 MW gross or greater are parallel to those of the Acid Rain Program, but for a smaller quantity of required data pursuant to SWCAA 97-2057R1 Section 30.

K3. NSPS Duct Burner Recordkeeping Requirements (Subpart Db)

This recordkeeping requirement originates from 40 CFR 60.49b (Subpart Db) and is included in SWCAA 01-2350R4. At first glance it might seem that the CEMS reporting requirements of 40 CFR 60.49b(g) might also apply because there is no exception from this reporting listed. However, 40 CFR 60.48b(h) clearly states that the owner or operator of an affected facility that is subject to the NO_X standards of 40 CFR 60.44b(a)(4) (for duct burners in combined cycle systems) is not required to install or operate a CEMS.

IX. EXPLANATION OF REPORTING TERMS AND CONDITIONS

R1. Deviations from Permit Conditions

The permittee is required to report all permit deviations promptly. This reporting requirement is taken directly from WAC 173-401-615(3) and is included in some form in SWCAA 97-2057R1 Sections 28, 29, and 37, SWCAA 01-2403 Section 11(e)(1), SWCAA 01-2350R4 Conditions 28(a & b), and PSD-01-01 Amendment 2 Condition 22(d)(1). SWCAA defines "prompt" in the permit in relation to the degree and type of deviation likely to occur and the applicable requirement. Excess emissions of SO_2, particulate matter, or opacity are to be reported to SWCAA during the current business day or next business morning. A written report may be requested by SWCAA, and shall be required for any SO_2 emission control technology forced outage longer than 72 hours. Any emissions released through a bypass duct without a certified functioning CEMS are defined as an upset condition which shall be reported to SWCAA during the current business day or by the next business morning and shall be documented to SWCAA within 5 days of occurrence. All other deviations must be reported no later than 30 days following the end of the month during which the deviation was discovered. This reporting frequency is taken from WAC 173-401-615(3).

R2. Complaint Reports

The permittee is required to report all complaints to SWCAA within three business days of receipt to ensure prompt complaint response. This reporting section is based on WAC 173-401-615(3), and SWCAA's definition of "prompt" for reporting of complaints.

R3. Quarterly Reports

The permittee is required to report monitoring records and certification of monitoring records on a quarterly basis for the Acid Rain Program. Although a semi-annual report on the status of, and certification of monitoring records is required by WAC 173-401-615(3),

quarterly reporting of specified monitoring records is required under 40 CFR 75.64, with compliance certification according to 40 CFR 75.64(c). Non-Acid Rain reporting requirements for the coal plant are derived from SWCAA 97-2057R1 Sections 27d, 43, and 45, and WAC 173-401-615(3). Non-Acid Rain reporting requirement for the combustion turbine facility are specified in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. Although records are reported quarterly, certification of non-Acid Rain monitoring records is only required every six months consistent with WAC 173-401-615(3).

R4. Semi-annual Reports

The permittee is required to provide a report of all monitoring records and provide a certification of all reports on a semi-annual basis. Semi-annual reporting and certification of monitoring records is required by WAC 173-401-615(3). A Responsible Official must certify all reports required by the Title V permit.

R5. Annual Reports and Compliance Certification

The permittee is required to report and certify compliance with all permit terms and conditions on an annual basis. Annual compliance certification is required by WAC 173-401-630(5) for all requirements and also by 40 CFR 72.90 for Acid Rain requirements (EU-1, EU-2, EU-7, EU-8, EU-9, and EU-10). In the annual compliance certification for each Acid Rain affected unit, the permittee or designated representative must indicate whether the unit held allowances in its compliance subaccount not less than the unit's total SO_2 emissions during the calendar year covered by the annual report. The permittee is required to indicate in the certification whether the monitoring plan is current, the monitors are properly certified, and all emissions were accounted for by monitoring or missing data procedures.

R6. Emission Inventory Reports

The permittee is required to report an inventory of emissions from the source on an annual basis. Annual reporting of emissions inventory is required under SWCAA 400-105 to be submitted to SWCAA by March 15th for the previous calendar year unless an extension is approved by SWCAA. SWCAA's Executive Director may extend the submittal date to April 15th (the deadline in WAC 173-400-105).

R7. Source Test Reports

The permittee is required to notify SWCAA in advance of all required source testing so that SWCAA personnel may be present during testing. The permittee shall also report test results within 45 days of test completion to allow timely review by SWCAA. Operating conditions are also to be included in all test reports to relate emissions to the method of operation. Source testing described in monitoring requirements M8 and M15 are examples of source test results subject to this reporting requirement.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions

This reporting section is taken from 40 CFR 75.60, 75.61 and 75.63 to indicate that the reporting requirements in these Acid Rain sections apply. Advance notification within specified time periods is required for the date each unit commences commercial operation, CEMS certification and recertification tests, relative accuracy test audits, and COMS certification and recertification tests at Acid Rain affected units. An application for certification or recertification is required for Acid Rain affected units. Each certification application is to be submitted in electronic or paper format as specified by the EPA Administrator. The permittee must comply with All Acid Rain reporting requirements in 40 CFR 75.60.

R9. Information on Boiler Condition in Support of NO_x Limit Modification

This reporting section is taken directly from SWCAA 97-2057R1 Section 33. The permittee was concerned that low-NO_X modifications could not meet the RACT Order NO_X emission limits. If the permittee seeks a modification of the NO_X limitations due to actual operation not meeting system expectations, the permittee is to report to SWCAA all causes of NO_X emissions higher than predicted by the system manufacturer by December 31, 2006. Permittee is to report to SWCAA by December 31, 2008 any excessive boiler waterwall tube corrosion attributed to the NO_X emission reduction system. Documentation of sub-standard performance or boiler corrosion in support of a NO_X limit modification is based on installation of Level III low-NO_X technology. Installation of a less-capable NO_X emission reduction technology voids permittee's ability to obtain a modification of the NO_X limitation under SWCAA 97-2057R1 Section 33. This requirement does not obligate the permittee to report to SWCAA, but rather establishes a deadline for reporting information on the boiler condition should the permittee desire a NO_X emission limit modification.

X. COMPLIANCE HISTORY

The following Field Notices of Correction (FNOC) or Field Notices of Violation (FNOV) have been issued during the last permit term (August 6, 2004 through August 5, 2009).

FNOC/ FNOV#	Violation Date	Notes
3521	6/28/06	1 hour exceedance of the NO_X mass emission rate limit for CT50 on June 28, 2006 due to human communication error when running CEMS linearity tests.
3520	7/22/06	Emissions exceeded 8-hour CO limit for two hours by CT40 on June 21, 2006 and for two hours on July 22, 2006. Cause is unknown. Emissions during these events were 1.6 – 1.7 ppmvd @ 15% O_2 (8-hr average). SWCAA required submittal of BACT analysis for CO.

FNOC/ FNOV#	Violation Date	Notes
3533	10/5/07 & 10/6/07	Exceedance of the bypass opacity limitations during maintenance to change the power source for the Unit #1 ID damper control. Fly ash was re-entrained with the cycling of the bypass and inlet dampers. Excess opacity experienced for 13 minutes on 10/5/07 and for 10 minutes on 10/6/07.
3528	10/12/07	1 hour exceedance of ammonia emission limit by CT30 due to overheating of the SCR catalyst bed after loss of feedwater pump. Exceedance could have been avoided by dropping load to reduce SCR catalyst temperature.
3529	7/16/07	Exceedance of the concentration (1 3-hr period) and mass emission rate (2 1-hour periods) NO_X emission limits for CT60 on July 16, 2007. Event was caused by miscommunication between instrument technician and plant operator.
3530	8/8/07	Exceedance of the hourly ammonia mass emission rate limit for CT60 on August 8, 2007. The exceedance reportedly occurred due to overheating of the SCR catalyst bed (resulting in decreased reaction between NO_X and NH_3). Because of the lower catalyst efficiency, maintaining the NO_X emission limit resulted in excessive ammonia slip. The cause of the bed overheating was a trip of the Once Through Steam Generator (OTSG) shortly after startup.
3531	8/9/07 & 8/24/07	1 hour of exceedance of CO emission limits by CT60 on each date. Each exceedance immediately followed a startup event and may have been related to a relatively high water injection rate into the turbine.
3532	8/15/07	1 hour exceedance of NO_X mass emission rate limit for CT60 on August 15, 2007. Caused by unintentional interruption of the power supply to the NO_X (turbine) water injection pump while installation of wiring on another system.
3542	4/9/08	1 hour exceedance of NO_X mass emission rate limit for CT30, CT40, and CT60 on April 9, 2008. After a manual CEMS calibration at 0100 the operator failed to recognize the calibrations had occurred and did not return the units to automatic control or manually adjust NH_3 injection to control NO_X in time to prevent an exceedance of the permitted emission limits during the 0200 hour.
3544	8/1/08	On-going failure of NH_3 CEMS in combustion turbine facility (all units) to pass local-only relative accuracy audit requirements. A compliance schedule was implemented to address this deficiency.
3547	9/22/08	Unit #2 experienced a 10 minute scrubber bypass event that resulted in excess visual emissions from the bypass stack. The bypass was triggered when a mechanic removed a level transmitter that was currently being used as the control for the Unit #2 scrubber because the isolation valve had been mislabeled during the spring outage.

FNOC/ FNOV#	Violation Date	Notes
4603	3/11/09	1 hour exceedance of NO_X mass emission rate limit by CT30 on March 11, 2009. Exceedance occurred when operator started a gas compressor to increase fuel pressure while CEMS indication was not available, and failed to address increasing NO_X emissions prior to re-calibrating the NH_3 CEMS.

XI. APPENDICES

Appendix A contains the methods by which visible emissions from the permittee's operations are to be evaluated when performing required monitoring. SWCAA has exercised its latitude under SWCAA 400-105(4) "Source Testing" to approve an alternative test method in advance for visible emissions. Approval has been granted via signature of SWCAA's Control Officer in this permit. The federal requirements still require that EPA Method 9 be performed. The difference between the Appendix A visible emission method and EPA Method 9 is the data reduction method used.

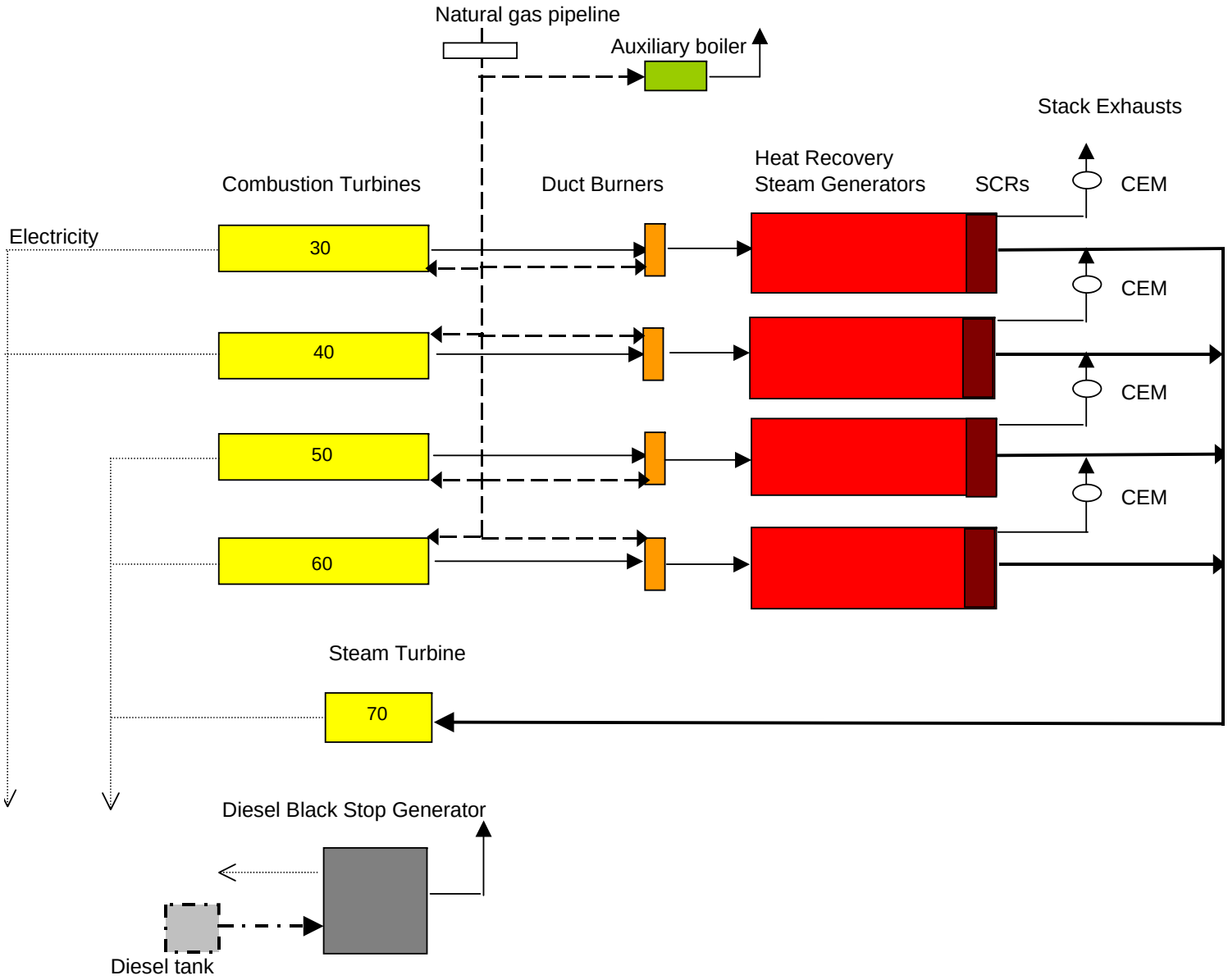
Appendix B contains the Acid Rain Permit for the Centralia Plant. The Acid Rain permit is effective beginning on the same date as this Air Operating Permit through the expiration date of this Air Operating Permit. Nearly all requirements in the Acid Rain permit are incorporated by reference to the applicable regulation, therefore changes in the applicable regulation are automatically incorporated into the permit.

XII. PERMIT ACTIONS

1.	Permit SW98-8 (original T5 permit) Issued:	August 6, 1999
2.	Permit SW98-8-R1 (Admin. Amend.) Issued:	July 12, 2000
3.	Permit SW98-8-R2 (First Renewal) Effective:	August 6, 2004
4.	Permit SW98-8-R2-A Issued:	May 12, 2005
5.	Permit SW98-8-R2-B Issued:	March 25, 2008
3.	Permit Renewal Application Received:	February 3, 2009
4.	Permit Application deemed complete:	March 17, 2009
5.	Permit Application sent to EPA:	To be determined
6.	Draft Permit Issued:	To be determined
7.	Proposed Permit Issued:	To be determined
8.	Final Permit (SW98-8-R3) Effective:	To be determined

XIII. PLANT DRAWINGS

Drawing #1 – Combustion Turbine Facility Flow Diagram



Drawing #2 – Forced Oxidized Limestone FGD System