TransAlta Centralia Generation, LLC

Centralia Plant

Title V Basis Statement

Issued: September 16, 2014

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

PERMIT #: SW98-8-R4

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. Maircse, Chief Engineer
# TABLE OF CONTENTS

I. General Information and Certification ................................................................. 1  
II. Emissions Unit Descriptions .............................................................................. 8  
III. Explanation of Insignificant Emissions Unit Determinations ......................... 27  
IV. Explanation of Selected Permit Provisions and General Terms and Conditions. 31  
V. Explanation of Operating Terms and Conditions ............................................. 32  
VI. Explanation of Obsolete and Future Requirements ........................................ 50  
VII. Explanation of Monitoring Terms and Conditions ......................................... 56  
VIII. Explanation of Recordkeeping Terms and Conditions .................................. 76  
IX. Explanation of Reporting Terms and Conditions ............................................ 78  
X. Compliance Summary ....................................................................................... 81  
XI. Appendices ....................................................................................................... 82  
XII. Permit Actions .................................................................................................. 82  
XIII. Plant Drawings ............................................................................................... 83
I. GENERAL INFORMATION AND CERTIFICATION

1. Company Name: TransAlta Centralia Generation, LLC
2. Facility Name: Centralia Plant
3. Contact Person: Bob Nelson, Plant Manager
4. Inspection Contact Person: Brian Brazil, Environmental Manager
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 known 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.

Facilitywide Potential To Emit Summary

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emissions (tons per year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen oxides</td>
<td>18,144</td>
</tr>
<tr>
<td>Carbon monoxide</td>
<td>16,160</td>
</tr>
<tr>
<td>Volatile organic compounds</td>
<td>190</td>
</tr>
<tr>
<td>Sulfur dioxide</td>
<td>10,039 (10,000 for coal plant, 39 for gas turbine plant)</td>
</tr>
<tr>
<td>Particulate Matter</td>
<td>3,831</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>2,937</td>
</tr>
<tr>
<td>PM$_{2.5}$</td>
<td>2,783</td>
</tr>
<tr>
<td>Combined HAPs</td>
<td>110</td>
</tr>
<tr>
<td>Individual HAP</td>
<td>56 (HF)</td>
</tr>
<tr>
<td>CO$_2$ equivalent</td>
<td>17,238,573</td>
</tr>
</tbody>
</table>

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-R3-A. The Air Operating Permit issued in response to TransAlta's renewal application has been updated as appropriate and includes new permit terms related to:
b. 40 CFR 63 Subpart UUUUU "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units"

c. First Revision of BART Order No. 6426 to establish NO\textsubscript{X} emission limits for EU-1 and EU-2 in accordance with the visibility protection program.

d. Air Discharge Permit 12-3016 for a replacement Fly Ash Weigh Bin Baghouse.

e. Air Discharge Permit 12-3035 for a new Fire Pump Engine.

9. Attainment Area:

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

10. Facility Description:

Coal Plant

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\textsubscript{2}), oxides of nitrogen (NO\textsubscript{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 670 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. Historically, coal was supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and stacked and reclaimed in the Centralia Plant's coal handling yard. A smaller portion of coal from the Powder River Basin in Wyoming was blended with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure that the hourly SO\textsubscript{2} emission limit continued to be met. The coal mine ceased active mining operations in November 2006 and currently all coal is supplied from the Powder River Basin. The coal mine could conceivably re-open and once again supply coal to the power plant in the future.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESP's) in series on each unit. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Mercury emissions are controlled an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the each boiler. The mercury control systems were completed November 24, 2011. NO\textsubscript{X} emissions are controlled with low-NO\textsubscript{X} burners with coupled over-fire air systems (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed on Unit #2 in 2001 and Unit #1 in 2002. The SNCR systems were installed on both units in 2012. 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 trucked to the Centralia Mine landfill.
site. Bottom ash is also sold, stockpiled, or 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 is available to provide backup electricity in the event of a plant shutdown during a total electrical grid failure.

NOX 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.

<table>
<thead>
<tr>
<th>Order/Permit Number</th>
<th>App. #</th>
<th>Date Issued</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>69-1107LET</td>
<td>L-1</td>
<td>11-7-69</td>
<td>Approval to construct Units #1 and #2</td>
</tr>
<tr>
<td>72-0804LET</td>
<td>N/A</td>
<td>8-4-72</td>
<td>Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing</td>
</tr>
<tr>
<td>72-0914LET</td>
<td>N/A</td>
<td>9-14-72</td>
<td>Approval given for operation at 400 MW</td>
</tr>
<tr>
<td>72-0610LET</td>
<td>N/A</td>
<td>10-6-72</td>
<td>Approval given for operation at 500 MW</td>
</tr>
<tr>
<td>72-1017LET</td>
<td>N/A</td>
<td>10-17-72</td>
<td>Approval to operate Unit #2 at full load for 48 hour demonstration</td>
</tr>
<tr>
<td>Order/Permit Number</td>
<td>App. #</td>
<td>Date Issued</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------</td>
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<td>-------------</td>
</tr>
<tr>
<td>72-1102LET</td>
<td>N/A</td>
<td>11-2-72</td>
<td>Approval to operate Unit #1 at same load as Unit #2</td>
</tr>
<tr>
<td>72-1211LET</td>
<td>N/A</td>
<td>12-11-72</td>
<td>Approval given for operation of each unit up to 500 MW, PM not to exceed 0.06 gr/dscf</td>
</tr>
<tr>
<td>73-0329LET</td>
<td>L-49</td>
<td>3-29-73</td>
<td>Approval to install SO3 conditioning system to aid PM removal in Koppers ESPs</td>
</tr>
<tr>
<td>73-0413LET</td>
<td>L-50</td>
<td>4-13-73</td>
<td>Approval to install second set of ESPs as pilot test</td>
</tr>
<tr>
<td>73-0426LET</td>
<td>N/A</td>
<td>4-26-73</td>
<td>Regulatory Order requiring testing to provide additional information on SO3 conditioning system</td>
</tr>
<tr>
<td>73-0504LET</td>
<td>N/A</td>
<td>5-4-73</td>
<td>Required testing and reporting for ESP pilot test program</td>
</tr>
<tr>
<td>73-0522LET</td>
<td>N/A</td>
<td>5-22-73</td>
<td>Modified dates and operating conditions specified in 4-4-73 letter</td>
</tr>
<tr>
<td>73-0611LET</td>
<td>N/A</td>
<td>6-11-73</td>
<td>Approval to operate Unit #1 at up to 700 MW w/ PM ( &lt; 0.06 \text{ gr/dscf} )</td>
</tr>
<tr>
<td>74-0702LET</td>
<td>L-50R</td>
<td>2-7-74</td>
<td>Approved design and installation of second set of ESPs</td>
</tr>
<tr>
<td>74-0222LET</td>
<td>N/A</td>
<td>2-22-74</td>
<td>Revision to clarify language in 2-7-74 letter</td>
</tr>
<tr>
<td>74-38</td>
<td>N/A</td>
<td>3-25-74</td>
<td>Specifies testing on Unit #2</td>
</tr>
<tr>
<td>74-38A</td>
<td>N/A</td>
<td>5-2-74</td>
<td>Extends high load testing days to 30</td>
</tr>
<tr>
<td>87-934</td>
<td>N/A</td>
<td>8-26-87</td>
<td>Order of Violation – Exceedance of 1,000 ppm SO2 limit, inconsistent with 1969 application, penalties levied, required to sample coal, stack SO2.</td>
</tr>
<tr>
<td>87-934-STAY</td>
<td>N/A</td>
<td>9-21-87</td>
<td>Order staying for 18 months requirements for SO2 sampling, coal S sampling, and withdrawing Order of Violation 87-934 if compliance with ambient SOX limits met despite being above 1,000 ppm limits.</td>
</tr>
<tr>
<td>88-934</td>
<td>N/A</td>
<td>2-24-88</td>
<td>Order, Withdrawal of Stay, and Modification of Order of Violation - Required to study lime injection, blend and wash coal install continuous SO2 and O2 emissions monitors, install ambient air quality monitors at three sites near the facility.</td>
</tr>
<tr>
<td>88-934B</td>
<td>N/A</td>
<td>7-14-98</td>
<td>Variance and Modification of Order – Modified SO2 averaging period, required ambient modeling and collection of meteorological data.</td>
</tr>
<tr>
<td>Order/Permit Number</td>
<td>App. #</td>
<td>Date Issued</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------</td>
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<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>88-934C</td>
<td>N/A</td>
<td>10-24-99</td>
<td>934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO₂ 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</td>
</tr>
<tr>
<td>90-934D</td>
<td>N/A</td>
<td>11-9-90</td>
<td>Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO₂ emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO₂ 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.</td>
</tr>
<tr>
<td>90-934E</td>
<td>N/A</td>
<td>4-5-91</td>
<td>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.</td>
</tr>
<tr>
<td>95-1787</td>
<td>N/A</td>
<td>8-25-95</td>
<td>RACT order limiting SO₂ emissions to 1.1 lb/MMBtu</td>
</tr>
<tr>
<td>96-1872</td>
<td>N/A</td>
<td>3-20-96</td>
<td>Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.</td>
</tr>
<tr>
<td>97-2057</td>
<td>N/A</td>
<td>12-8-97</td>
<td>Determination of SO₂, NOₓ, CO and PM RACT, SO₂ and NOₓ controls</td>
</tr>
<tr>
<td>97-2057R1</td>
<td>N/A</td>
<td>2-26-98</td>
<td>Revision of RACT determination</td>
</tr>
<tr>
<td>99-2187</td>
<td>N/A</td>
<td>2-1-99</td>
<td>Stay Order extending the date when procurement contract for Unit #1 control technology must be signed by 60 days (new date May 31, 1999).</td>
</tr>
<tr>
<td>01-2350</td>
<td>L-480</td>
<td>5-30-01</td>
<td>Minor source permit for combustion turbine project. Does not address PM or NOₓ emissions</td>
</tr>
<tr>
<td>PSD-01-01</td>
<td>N/A</td>
<td>2-22-02</td>
<td>PSD permit for combustion turbine project – addresses PM and NOₓ emissions</td>
</tr>
<tr>
<td>Order/Permit Number</td>
<td>App. #</td>
<td>Date Issued</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------</td>
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</tr>
<tr>
<td>01-2403</td>
<td>L-490</td>
<td>2-27-02</td>
<td>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</td>
</tr>
<tr>
<td>01-2350R1</td>
<td>L-496</td>
<td>5-6-02</td>
<td>Modification of 01-2350 primarily to increase SO₂ limit to account for higher sulfur content in natural gas</td>
</tr>
<tr>
<td>PSD-01-01 Amendment 1</td>
<td>N/A</td>
<td>1-30-03</td>
<td>Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler</td>
</tr>
<tr>
<td>01-2350R2</td>
<td>L-505</td>
<td>10-15-03</td>
<td>Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.</td>
</tr>
<tr>
<td>PSD-01-01 Amendment 2</td>
<td>N/A</td>
<td>6-11-04</td>
<td>Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required.</td>
</tr>
<tr>
<td>01-2350R3</td>
<td>L-552</td>
<td>5-12-05</td>
<td>Modification of source testing and RATA frequencies for Combustion Turbine Facility</td>
</tr>
<tr>
<td>05-2612</td>
<td>L-556</td>
<td>7-15-05</td>
<td>Expansion of West Coal Unloading Facility with addition of 1 hopper</td>
</tr>
<tr>
<td>05-2636</td>
<td>L-565</td>
<td>11-23-05</td>
<td>Installation of FGD Bleed Treatment Lime Storage Silo</td>
</tr>
<tr>
<td>07-2712</td>
<td>L-590</td>
<td>2-7-07</td>
<td>Modification of West Coal Unloading Facility with surge capacity addition</td>
</tr>
<tr>
<td>07-2749</td>
<td>L-603</td>
<td>9-26-07</td>
<td>Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility. After removal of the West Coal Unloading Facility in 2011, East Coal Unloading Facility simply referred to as the Coal Unloading Facility.</td>
</tr>
<tr>
<td>01-2350R4</td>
<td>L-608</td>
<td>1-18-08</td>
<td>Elimination of 1.5 ppmvd @ 15% O₂ (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O₂ (1-hour average) limit was retained.</td>
</tr>
<tr>
<td>08-2779</td>
<td>L-613</td>
<td>3-12-08</td>
<td>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</td>
</tr>
<tr>
<td>Order/Permit Number</td>
<td>App. #</td>
<td>Date Issued</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------</td>
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</tr>
<tr>
<td>09-2876</td>
<td>L-634</td>
<td>6-16-09</td>
<td>Installation and operation of a 251 horsepower nonroad engine that will drive a Jetstream pressure washer. The engine and pressure washer package will be mounted on a mobile trailer for use throughout the power plant and associated facilities. Because this is a non-road engine, it is not part of the facility's Title V permit.</td>
</tr>
<tr>
<td>Order No. 6426</td>
<td>N/A</td>
<td>6-18-10</td>
<td>BART Order from Washington Department of Ecology establishing NOX emission limit of 0.24 lb/MMBtu for the coal fired boilers and coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.</td>
</tr>
<tr>
<td>11-2972</td>
<td>L-647</td>
<td>4-14-11</td>
<td>Installation and operation of an emergency water pump at the (East) CUF powered by a diesel engine. Superseded 07-2749.</td>
</tr>
<tr>
<td>11-2984</td>
<td>L-650</td>
<td>6-14-11</td>
<td>Installation of equipment associated with activated carbon injection mercury emission control system.</td>
</tr>
<tr>
<td>11-2996</td>
<td>L-654</td>
<td>11-3-11</td>
<td>Installation and operation of the Pump 8 Engine. This permit also addressed the grandfathered engine on Barge 5429. Note that Pump 8 was subsequently referred to as the Pump-05 engine.</td>
</tr>
<tr>
<td>First Revision of Order No. 6426</td>
<td>N/A</td>
<td>12-13-11</td>
<td>Revision of BART Order 6426 with new requirements for SNCR.</td>
</tr>
<tr>
<td>12-3016</td>
<td>L-657</td>
<td>4-30-12</td>
<td>Installation of a baghouse to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America), and the relatively new &quot;Fly Ash Bin 11 to Weight Hopper Air Slide Filter&quot; (operated by TransAlta). The new baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the #11 Air Slide and the #12 Air Slide.</td>
</tr>
<tr>
<td>12-3035</td>
<td>L-659</td>
<td>10-18-12</td>
<td>Installation of a new fire pump engine that may also be used to supply water to other systems at the plant during a maintenance event. Superseded 11-2996.</td>
</tr>
<tr>
<td>14-3093</td>
<td>L-668</td>
<td>4-30-14</td>
<td>Approval of coal mine waste reprocessing activities and fine coal recovery at TransAlta Centralia Mining and delivery by conveyor to TransAlta Centralia Generation.</td>
</tr>
</tbody>
</table>
## II. EMISSIONS UNIT DESCRIPTIONS

### Summary Table

<table>
<thead>
<tr>
<th>EU #</th>
<th>Generating Equipment</th>
<th>Emission Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU-1</td>
<td>Unit #1 Boiler (BW21) – 670 MW (net), coal fired</td>
<td>CO: Combustion controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO\textsubscript{X}: Combustion controls, SNCR</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Combustion controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: Dual ESPs, wet scrubber</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO\textsubscript{2}: Wet scrubber</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hg: Sorbent enhancement additive in boiler. carbon injection between ESPs</td>
</tr>
<tr>
<td>EU-2</td>
<td>Unit #1 Boiler (BW22) – 670 MW (net), coal fired</td>
<td>CO: Combustion controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO\textsubscript{X}: Combustion controls, SNCR</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Combustion controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: Dual ESPs, wet scrubber</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO\textsubscript{2}: Wet scrubber</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hg: Sorbent enhancement additive in boiler. carbon injection between ESPs</td>
</tr>
<tr>
<td>EU-3</td>
<td>Auxiliary Boiler – 170 MMBtu/hr, oil-fired</td>
<td>Fuel consumption limit</td>
</tr>
<tr>
<td>EU-4</td>
<td>Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime</td>
<td>Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facilities</td>
</tr>
<tr>
<td></td>
<td>Storage Silo, Limestone Ball Mill)</td>
<td>Ash Handling – baghouse, wet suppression, and enclosure as appropriate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>FGD Bleed Treatment Lime Storage Silo – Baghouse</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Limestone Ball Mill – Wet process, full enclosure</td>
</tr>
<tr>
<td>EU-5</td>
<td>Turbine Lube Oil Mist Vent #1</td>
<td>Turbine Lube Oil Mist Eliminator #1</td>
</tr>
<tr>
<td>EU-6</td>
<td>Turbine Lube Oil Mist Vent #2</td>
<td>Turbine Lube Oil Mist Eliminator #2</td>
</tr>
<tr>
<td>EU-7</td>
<td>Combustion Turbine 30 – GE LM6000 with 105 MMBtu/hr of duct firing capability</td>
<td>CO: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO\textsubscript{X}: Selective catalytic reduction system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: No controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO\textsubscript{2}: No controls</td>
</tr>
<tr>
<td>EU-8</td>
<td>Combustion Turbine 40 – GE LM6000 with 105 MMBtu/hr of duct firing capability</td>
<td>CO: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO\textsubscript{X}: Selective catalytic reduction system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: No controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO\textsubscript{2}: No controls</td>
</tr>
<tr>
<td>EU-9</td>
<td>Combustion Turbine 50 – GE LM6000 with 105 MMBtu/hr of duct firing capability</td>
<td>CO: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO\textsubscript{X}: Selective catalytic reduction system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: No controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SO\textsubscript{2}: No controls</td>
</tr>
<tr>
<td>EU #</td>
<td>Generating Equipment</td>
<td>Emission Control</td>
</tr>
<tr>
<td>-------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EU-10</td>
<td>Combustion Turbine 60 – GE LM6000 with 105 MMBtu/hr of duct firing capability</td>
<td>CO: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NOX: Selective catalytic reduction system</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: Oxidation catalyst</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM: No controls</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SOX: No controls</td>
</tr>
<tr>
<td>EU-11</td>
<td>Black Stop Diesel Generator Engine – 1,445 hp diesel engine</td>
<td>Operating hours limit</td>
</tr>
<tr>
<td>EU-12</td>
<td>BHP Auxiliary Boiler – 20.9 MMBtu natural gas fired package boiler</td>
<td>Low-NOX burners, no add-on controls</td>
</tr>
<tr>
<td>EU-13</td>
<td>Journal Shop Welding</td>
<td>Journal Shop Welding Filter</td>
</tr>
<tr>
<td>EU-14</td>
<td>Emergency Diesel Generator #1</td>
<td>None</td>
</tr>
<tr>
<td>EU-15</td>
<td>Emergency Diesel Generator #2</td>
<td>None</td>
</tr>
<tr>
<td>EU-16</td>
<td>Fire Pump Engine (205 hp diesel engine)</td>
<td>Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit</td>
</tr>
<tr>
<td>EU-17</td>
<td>Barge 5429 Engine (250 hp diesel engine, pre 2002)</td>
<td>None</td>
</tr>
<tr>
<td>EU-18</td>
<td>Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)</td>
<td>Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit</td>
</tr>
<tr>
<td>EU-19</td>
<td>SEA System #1</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-20</td>
<td>SEA System #2</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-21</td>
<td>Sorbent Silo #1</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-22</td>
<td>Sorbent Silo #2</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-23</td>
<td>Fly Ash Bin 11</td>
<td>Baghouse</td>
</tr>
<tr>
<td>EU-24</td>
<td>Fly Ash Bin 12</td>
<td>Baghouse</td>
</tr>
<tr>
<td>EU-25</td>
<td>Fly Ash Bin 14</td>
<td>Baghouse</td>
</tr>
<tr>
<td>EU-26</td>
<td>Fly Ash Bin 14 Air Slide to Bin 11 Air Slide</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-27</td>
<td>Fly Ash Bin 14 to 6050 Air Slide</td>
<td>Cartridge-style Fabric Filter</td>
</tr>
<tr>
<td>EU-28</td>
<td>Pump-05 Engine (115 hp diesel engine, pre 2002)</td>
<td>Ultra low sulfur fuel, EPA Tier 1 design, operating hours limit</td>
</tr>
<tr>
<td>EU-29</td>
<td>Fine Coal Handling</td>
<td>Wet suppression</td>
</tr>
</tbody>
</table>

Collectively EU-1, EU-2, EU-3, EU-4, EU-5, EU-6, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, EU-22, EU-23, EU-24, EU-25, EU-26, EU-27, EU-28, & EU-29 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.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control system was completed November 24, 2011. NO$_X$ emissions are controlled with low-NO$_X$ burners with coupled over-fire air (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed in 2002.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of each boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on each boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

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

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Facility Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>One boiler for Unit #1</td>
<td>Unit #1 or BW21</td>
</tr>
<tr>
<td>Two ESP units in series</td>
<td>Koppers 11 &amp; 12; Lodge-Cottrell 11A &amp; 12A</td>
</tr>
<tr>
<td>Unit #1 wet scrubber</td>
<td>FGD #1</td>
</tr>
</tbody>
</table>

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

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.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the each boiler. The mercury control system was completed November 24, 2011. NO$_X$ emissions are controlled with low-NO$_X$ burners with coupled over-fire air (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed in 2001. The SNCR system was installed in 2012.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of each boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on each boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

The following individual pieces of equipment are associated with EU-2:
Equipment
One Boiler for Unit #2
Two ESP units in series
Unit #2 wet scrubber

Facility Designation
Unit #2 or BW22
Koppers 21 & 22; Lodge-Cottrell 21A & 22A
FGD #2


Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

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 NOx, SO2, CO, PM, and VOCs from combustion of #2 fuel oil.

Construction of EU-3 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 Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Note that prior to 2011 there were two Coal Unloading facilities. One located at the West end of the plant site and one located the East end of the plant site. The West Coal Unloading Facility was removed from service in 2011. Except for descriptions in historical context all coal is unloaded at a single point: the Coal Unloading Facility formerly known as the East Coal Unloading Facility. In 2007 the permittee received an Air Discharge Permit to construct the 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:

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Facility Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Unloading Facility</td>
<td>CUF</td>
</tr>
<tr>
<td>Twelve coal conveyors</td>
<td>Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, &amp; 22</td>
</tr>
<tr>
<td>One bucket-wheel stacker-reclaimer</td>
<td>Stacker-reclaimer</td>
</tr>
<tr>
<td>Coal blending system</td>
<td></td>
</tr>
<tr>
<td>Chemical stabilizing dust suppression systems</td>
<td>(N/A)</td>
</tr>
<tr>
<td>at CUF and #5 reclaim</td>
<td></td>
</tr>
<tr>
<td>Eight coal silos for each unit</td>
<td>Silos 11-18 (Unit #1), 21-28 (Unit #2)</td>
</tr>
<tr>
<td>Coal surge bin</td>
<td>(N/A)</td>
</tr>
<tr>
<td>Four bottom ash dewatering bins</td>
<td>Bins 11, 12, 21, 22</td>
</tr>
<tr>
<td>Various mobile machinery</td>
<td>(N/A)</td>
</tr>
<tr>
<td>Four fly ash bins</td>
<td>Bins 11, 12, 13, 14</td>
</tr>
</tbody>
</table>

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
Bin 13 – Repurposed as a boron removal clarifier in the FGD Bleed Treatment system
Bin 14 – Replaced into service in 2011 to handle fly ash from the Lodge-Cottrell that contains carbon sorbent from the mercury control system.

| Fly Ash Weigh Bin Baghouse                      | Same                                               |
| FGD Bleed Treatment Lime Storage Silo           | Same                                               |
| Limestone Ball Mill                             | Same                                               |

Coal Unloading Facility Details
The 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 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 ground level reclaims 3, 3A
7. Reclaims 3, 3A to Conveyor 4 or 4A (which feed the plant)

The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity. The Coal Unloading Facility began operation on February 1, 2008.

FGD Bleed Treatment Lime Storage Silo Details
The FGD Bleed Treatment Lime Storage Silo stores hydrated lime (Ca(OH)\textsubscript{2}). The lime is used to treat a bleed stream of scrubber liquid from the flue gas desulfurization system. The scrubber liquid treatment system is designed to reduce boron and zinc levels in the wastewater. The 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\textregistered 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" long
Cleaning Method: Reverse Pulse-Jet
Cloth Area: 270 ft\textsuperscript{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
Installed: 2006

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
Fly Ash Weigh Bin Baghouse Details
The Fly Ash Weigh Bin receives fly ash from the #11 Air Slide and the #12 Air Slide. The Fly Ash Weigh Bin was manufactured by Halliburton and has a capacity of up to 30,000 pounds. During normal operation, approximately 900 cfm of fluidizing air from one of the air slides is vented out of the Fly Ash Weigh Bin Baghouse. The Fly Ash Weigh Bin Baghouse draws approximately 900 cfm of air from the fly ash loading spout to control fugitive dust while loading, for a total airflow of 1,800 cfm. At times total airflow could range up to 2,700 cfm if fly ash were being loaded into the Fly Ash Weigh Bin from both air slides (i.e. more than one Fly Ash Bin) simultaneously. The Fly Ash Weigh Bin Baghouse will be turned on/off by the contractor in charge of loading fly ash (currently Lafarge North America), however TransAlta will retain responsibility for maintenance of, and the emissions from, the Fly Ash Weigh Bin Baghouse. The following details of the cartridge collector were provided:

<table>
<thead>
<tr>
<th>Baghouse Make / Model:</th>
<th>Donaldson Torit / Powercore CPV-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed:</td>
<td>Installation completed July 30, 2012</td>
</tr>
<tr>
<td>Design Flow Rate:</td>
<td>2,700 cfm (rated at 1,400 cfm to 2,700 cfm)</td>
</tr>
<tr>
<td>Filter Description:</td>
<td>4 cartridges (7&quot; wide x 22&quot; long x 7.5&quot; tall), total of 252 ft² filter area</td>
</tr>
<tr>
<td>Filter Description:</td>
<td>Ultra-web nanofiber material</td>
</tr>
<tr>
<td>Cleaning Method:</td>
<td>Pulsed jet – collected fly ash will drop down into the fly ash weigh bin</td>
</tr>
<tr>
<td>Stack Description:</td>
<td>16&quot; inside diameter stack exhausting vertically approximately 8' above the top of the fly ash weigh bin and 49-50' above ground level. An 18&quot; diameter shroud (stack within a stack design) may be used to prevent rain intrusion into the stack</td>
</tr>
</tbody>
</table>

Applicable NSPS/NESHAP/MACT: None

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™ 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/m³ and a temperature of 120°F. The mist eliminator utilizes 67 ft² (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 ft²).

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/m³ and a temperature of 120°F. The mist eliminator utilizes 67 ft² (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 ft²).

EU-7 Combustion Turbine 30

Combustion Turbine 30 is a General Electric LM6000 Sprint natural gas fired combustion turbine (original 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 (NOₓ) 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.

Note that Combustion Turbine 30 was damaged beyond repair in 2010 and the damaged unit has not been replaced at this time. Depending on the extent of the damage beyond the turbine section, replacement/repair of the turbine unit may not be considered reconstruction or installation of a new source for the purposes of the New Source Performance Standards (40 CFR 60) or New Source Review.

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart GG

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 (NOₓ) 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.

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart GG

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 (NOx) 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.

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart GG

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 (NOx) 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.

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart GG

EU-11 Black Stop Diesel Generator Engine

At the Combustion Turbine Facility 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 cooldown. 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.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

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 NOX emissions of 20 ppm @ 3% O2 or less. CO emissions are guaranteed not to exceed 50 ppm @ 3% O2. The boiler is equipped with an O2 trim system.

The BHP Auxiliary Boiler was built in 2001.

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart Dc
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
Stack Description: Exhausts horizontally through two 24" x 24" x 12" ducts at ambient temperature ~12' above grade.

Applicable NSPS/NESHAP/MACT: None

EU-14 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) for an insignificant emission unit. This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart ZZZZ. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ
EU-15 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 1/4 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). This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart ZZZZ. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

EU-16 Fire Pump Engine

The Fire Pump Engine drives a backup fire water pump. This unit will operate for testing and maintenance of the engine, as necessary during an emergency, and for limited time periods for non-emergency operation (e.g. during maintenance events when the electrical pump system is unavailable). Total annual operation is expected to be no more than 504 hours per year (3 weeks). Engine details are provided below:

Engine Make / Model: Cummins / CFP7E-F30 Fire Pump Driver
Engine Serial Number: 73467344
Fuel: Diesel, 10.6 gallons per hour at full load
Engine Power: 205 hp
Engine Built: 2012
Engine Installed: Installation completed December 27, 2012
Engine Certification: EPA Tier 3
Stack Description: ~ 4" diameter, exhausting vertically ~18' above grade, 1'
10" above roof level, stack flow 1,174 acfm @ 879°F
Location: 46°45'22.44"N, 122°51'44.23"W

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

EU-17 Barge 5429 Engine

Engine Rating: 250 horsepower
Engine Make / Model: Caterpillar / 3306
Engine #: Not Provided
Date of Manufacture: Prior to 2002

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ
EU-18 Coal Unloading Facility Emergency Diesel Sump Pump Engine

The CUF Emergency Diesel Sump Pump consists of a Godwin water pump driven by a diesel engine. The engine will only be operated for testing, maintenance, and as an emergency backup to the existing electric water pump. Engine details are provided below:

- Engine Make / Model: John Deere / 4045TF275
- Engine Serial Number: PE 4045TF593425
- Engine Family: 6JDXL06.8082
- Fuel: Diesel, 42.7 pounds per hour @ full load
- Horsepower Rating: 115
- Engine Built: July 9, 2006
- Engine Certification: EPA Tier 2
- Stack Description: ~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 713 acfm @ 860 °F

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart III

EU-19 SEA System #1

Based on a review of the potential Sorbent Enhancement Additive (SEA) materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions will be associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System #1 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

- Make / Model: Grünergy Technologies / PV-2-160 AR III
- Design Flow Rate: 1,130 cfm
- Design Exhaust Concentration: 0.005 gr/dscf
- # of Cartridge: 2
- Filter Description: 160 ft² of 8 oz/yd² thermally fused polyester with PTFE membrane
- Cleaning Method: Pulsed jet
- Stack Description: 6" diameter stack exhausting vertically on east wall of the boiler building.

EU-20 SEA System #2

Based on a review of the potential SEA materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions will be associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System #2 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

- Make / Model: Grünergy Technologies / PV-2-160 AR III
- Design Flow Rate: 1,130 cfm
TransAlta - Centralia Plant

Design Exhaust Concentration: 0.005 gr/dscf
# of Cartridges: 2
Filter Description: 160 ft² of 8 oz/yd² thermally fused polyester with PTFE membrane
Cleaning Method: Pulsed jet
Stack Description: 6" diameter stack exhausting vertically on east wall of the boiler building.

EU-21 Sorbent Silo #1

Sorbent Silo #1 will be located directly north of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following details of the vent filter system were provided:

Make / Model: Torit Technologies / TBV-4 Insertable
Design Flow Rate: 350 cfm, passively vented
Design Exhaust Concentration: 0.005 gr/dscf
Filter Description: 4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft² of 8 oz/yd² nanofiber on cellulose material
Cleaning Method: Reverse air jet
Stack Description: Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

EU-22 Sorbent Silo #2

Sorbent Silo #2 will be located directly south of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following equipment details were provided:

Make / Model: Torit Technologies / TBV-4 Insertable
Design Flow Rate: 350 cfm, passively vented
Design Exhaust Concentration: 0.005 gr/dscf
Filter Description: 4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft² of 8 oz/yd² nanofiber on cellulose material
Cleaning Method: Reverse air jet
Stack Description: Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

EU-23 Fly Ash Bin 11 Baghouse

The Fly Ash Bin 11 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model: Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate: 14,730 cfm
TransAlta - Centralia Plant

Design Exhaust Concentration: 0.005 gr/dscf
Filter Description: 256 bags, 114 inches long with a total filter area of 4,997 ft², top load, DuPont Type 54 or equal, polyester material.
Cleaning Method: Reverse air jet
Stack Description: Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector: Tribo-Flow model 4001-1111-01-154N with 12" long probe

EU-24 Fly Ash Bin 12 Baghouse

The Fly Ash Bin 12 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model: Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate: 14,730 cfm
Design Exhaust Concentration: 0.005 gr/dscf
Filter Description: 256 bags, 114 inches long with a total filter area of 4,997 ft², top load, DuPont Type 54 or equal, polyester material.
Cleaning Method: Reverse air jet
Stack Description: Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector: Tribo-Flow model 4001-1111-01-154N with 12" long probe

EU-25 Fly Ash Bin 14 Baghouse

The Fly Ash Bin 14 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model: Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate: 14,730 cfm
Design Exhaust Concentration: 0.005 gr/dscf
Filter Description: 256 bags, 114 inches long with a total filter area of 4,997 ft², top load, DuPont Type 54 or equal, polyester material.
Cleaning Method: Reverse air jet
Stack Description: Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the
TransAlta - Centralia Plant

Leak Detector:

- Baghouse, approximately 30' above the top of the fly ash bin.
- Tribo-Flow model 4001-111-I-154N with 12" long probe

**EU-26 Fly Ash Bin 14 Air Slide to Bin 11 Air Slide**

The air slide utilizes approximately 900 cfm of air to help move fly ash from Fly Ash Bin 14 to the Bin 11 Air Slide which in turn moves fly ash to the weigh hopper. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

- **Make / Model:** DCL / VML185
- **Design Flow Rate:** 900 cfm
- **Design Exhaust Concentration:** 0.005 gr/dscf
- **Filter Description:** 4 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 185 ft²
- **Cleaning Method:** Reverse air jet
- **Stack Description:** Exhaust will be approximately 35 feet above ground on the south side of the Bin 11 building – discharged vertically through ~ 6" diameter exhaust.

**EU-27 Fly Ash Bin 14 to 6050 Air Slide**

The air slide utilizes approximately 600 cfm of air to help move fly ash from Fly Ash Bin 14 to the 6050 unloader. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

- **Make / Model:** DCL / VML140
- **Design Flow Rate:** 600 cfm
- **Design Exhaust Concentration:** 0.005 gr/dscf
- **Filter Description:** 3 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 140 ft²
- **Cleaning Method:** Reverse air jet
- **Stack Description:** Exhaust will be approximately 35 feet above ground inbetween the Bin 11 and Bin 14 buildings discharged vertically through ~ 6" diameter exhaust.

**EU-28 Pump-05 Engine**

Pump-05 consists of a Godwin CD225M water pump driven by a diesel engine. Pump-05 is expected to operate primarily during the summer season at Pond 8 to circulate water for algae control. Pump-05 could be used elsewhere on the plant site during other times of the year, with total annual operation of no more than 2,000 hours. Engine details are provided below:
Engine Make / Model: John Deere / 4045TF275  
Engine Serial Number: PE4045T246562  
Engine Family: 2JDXL06.8014  
Fuel: Diesel, 5.8 gallons per hour @ full load  
Engine Power: 115 hp (86 kW)  
Engine Built: December 12, 2002  
Engine Certification: EPA Tier 1  
Stack Description: ~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 623 acfm @ 833°F  
Primary Location: Pond 8 ~ UTM 10T: 510734 m E, 5178575 m N

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

EU-29 Fine Coal Handling

Coal mine waste reprocessing and fine coal recovery activities at the Centralia Mine were approved in 2014. The activities involve dredging waste coal fines from ponds, processing those materials to separate fine coal from waste material, transferring waste slurry to a pit in the North Hanaford area, and transferring fine coal to the coal stockpile at TransAlta Generation. Fugitive dust may be generated at unenclosed material transfer points.

The fine coal handling equipment spans both the TransAlta Centralia Generation and TransAlta Centralia Mining facilities. Each facility maintains separate Air Operating Permits. TransAlta has indicated that after construction is complete, all equipment from Transfer Point 04 (TP-04) and downstream (including the fine coal stockpile) will be the responsibility of TransAlta Centralia Generation. An enclosed conveyor will transfer fine coal over Big Hanaford Road from TransAlta Centralia Mining to TransAlta Centralia Generation. TP-04 is the first transfer point north of Big Hanaford Road. Responsibility for the equipment upstream of TP-04 will be retained by TransAlta Centralia Mining.

<table>
<thead>
<tr>
<th>Transfer Point (TP)</th>
<th>Emission Control Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>TP-01 (screen bowl centrifuge to clean coal collection conveyor)</td>
<td>Fully enclosed and in the process building</td>
</tr>
<tr>
<td>TP-02 (clean coal collection conveyor to 48&quot; conveyor)</td>
<td>Fully enclosed</td>
</tr>
<tr>
<td>TP-03 (48&quot; conveyor to conveyor over Big Hanaford Road)</td>
<td>Fully enclosed</td>
</tr>
<tr>
<td>TP-04 (transfer either to existing conveyor to directly feed power plant or transfer to fixed stacker for periods when the power plant is not running. A flop gate will direct the flow.)</td>
<td>Fully enclosed</td>
</tr>
<tr>
<td>TP-05 (discharge from the stacking conveyor to clean coal stockpile - estimated to be 15% of total throughput)</td>
<td>High pressure suppression as necessary at stacker discharge.</td>
</tr>
</tbody>
</table>
Conveyor Descriptions

Conveyor from TP-01 to TP-02 (Clean Coal Collection Conveyor): This 24" conveyor passes through the process building wall and will be covered, but not fully enclosed, where it exits the building.

Conveyor from TP-02 to TP-03: 48" conveyor running along the south side of Parking Lot #2. This conveyor will be covered but not fully enclosed.

Conveyor from TP-03 to TP-04 (conveyor over Big Hanford Road): This conveyor is fully enclosed with the exception of some portal sized openings and open sides for a short distance near the head and tail pulleys.

Conveyor from TP-04 to Power Plant: This is an existing conveyor that runs along the south side of the coal plant stockpile and feeds the power plant.

Conveyor to TP-04 to Stockpile: This is an existing stacker that will be re-located to this fixed location. This is a 250' long open conveyor.

Applicable NSPS: 40 CFR 60 Subpart Y "Standards of Performance for Coal Preparation and Processing Plants".

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-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 PM10/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:

\[ 2,000 \text{ lb} \times \frac{(82 \text{ lb}/1,000 \text{ lb})}{(1 \text{ ton}/2,000 \text{ lb})} < 0.1 \text{ ton/yr} \]

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers for the Coal Plant (Unit #1 Boiler (EU-1), Unit #2 Boiler (EU-2)) and the Combustion Turbine Facility (EU-7, EU-8, EU-9, EU-10). The cooling towers 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:

\[
12,000 \text{ lb/yr} \times (1 - 0.92) \times (1 \text{ ton/2,000 lb}) = 0.48 \text{ tons per year VOC}
\]

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:

\[
220,000 \text{ gal} \times 0.079 \text{ lb/1,000 gal} \times (1 \text{ ton/2,000 lb}) = 0.009 \text{ tons per year VOC}
\]

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:

\[
220,000 \text{ gal} \times 0.079 \text{ lb/1,000 gal} \times (1 \text{ ton/2,000 lb}) = 0.009 \text{ tons per year VOC}
\]

IEU-73 Gasoline Storage Tank

The tank is a 5,200 gallon above ground tank with a white concrete shell used to fuel vehicles and equipment on site. The tank utilizes submerged fill and is not equipped with Stage I or II vapor recovery. No pressure/vacuum valve is utilized. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, well below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d).

Gasoline vapors are emitted primarily from the following:
1. Storage Tank Loading Losses
2. Storage Tank Breathing Losses

Storage tank loading and breathing losses were estimated using EPA's Tanks 4.09D emission estimation software.
The parameters were used in Tanks 4.09D:
Nearest City: Olympia, WA
Type of Tank: Horizontal Tank
Shell Length: 12.5’
Shell Diameter: 9’
Tank Volume: 5,200 gallons
Shell Color: White
Shell Condition: Poor
Vacuum Setting: 0.0 psi
Pressure Setting: 0.0 psi
Liquid: Gasoline (RVP=10)

Based on EPA Speciate 3.2 profile number 2455, approximately 50.85% of the total VOC emissions are toxic air pollutants (TAPs) as defined by WAC 173-460, and approximately 12.91% of the total VOC emissions are federally listed hazardous air pollutants (HAPs). For a throughput of 930,000 gallons per year, TAP and HAP emission rates are estimated to be:

<table>
<thead>
<tr>
<th>IEU-73 Gasoline Storage Tank Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Throughput =</td>
</tr>
<tr>
<td>Control Efficiency =</td>
</tr>
<tr>
<td><strong>Emission Factors</strong></td>
</tr>
<tr>
<td>Storage Tank Working Losses =</td>
</tr>
<tr>
<td>Storage Tank Breathing Losses =</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Emissions Summary</th>
<th>lbs</th>
<th>tons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volatile Organic Compounds</td>
<td>876</td>
<td>0.44</td>
</tr>
<tr>
<td>Toxic Air Pollutants</td>
<td>446</td>
<td>0.22</td>
</tr>
<tr>
<td>Hazardous Air Pollutants</td>
<td>113</td>
<td>0.06</td>
</tr>
</tbody>
</table>

**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:

\[ 16,000 \text{ gal} * 0.020 \text{ lb/1000 gal} * (1 \text{ ton/2,000 lb}) = 0.0002 \text{ tons per year VOC} \]
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:

\[
300 \text{ gal} \times 0.034 \text{ lb/1,000 gal} \times (1 \text{ ton}/2,000 \text{ lb}) = 0.00001 \text{ tons per year VOC}
\]

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 an annual throughput of 300 gallons, VOC emissions are calculated to be:

\[
300 \text{ gal} \times 0.034 \text{ lb/1,000 gal} \times (1 \text{ ton}/2,000 \text{ lb}) = 0.00001 \text{ tons per year VOC}
\]

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:

\[
150 \text{ gal} \times 0.47 \text{ lb/1,000 gal} \times (1 \text{ ton}/2,000 \text{ lb}) = 0.00004 \text{ tons per year VOC}
\]

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 maximum for material handling silo filters), potential emissions are:

\[
\frac{1,796 \text{ hours per year} \times 900 \text{ cubic feet} \times 60 \text{ minutes}}{\text{year} \times \text{minute} \times \text{hour}} \times 0.005 \text{ grains} \times \frac{1 \text{ pound}}{7,000 \text{ grains}} = 69 \text{ pounds per year}
\]

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.
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 maximum for material handling silo filters), potential emissions are:

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

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 M9 and M15 - Startup, Shut Down, and Outage Operation Procedures.

The Utility MACT (Subpart UUUUU) and the Boiler MACT (Subpart DDDDDD) are federally standards that can be delegated to state and local agencies and contain specific, and more restrictive, affirmative defense provisions that apply only to malfunctions. For these reasons, SWCAA has concluded that the state and local excess emission provisions cannot apply to these standards.
G2. Chemical Accident Prevention
[40 CFR 68]

Part 68 requires risk management plans be developed for the substances and thresholds listed in 40 CFR 68.130. Chlorine and ammonia are listed substances. The permittee no longer uses chlorine on site and will only use aqueous ammonia with a concentration of less than 20% by weight (only ammonia at 20% or greater concentration is listed in Part 68). The permittee uses no other substance listed in 40 CFR 68.130, therefore this standard does currently not apply to this facility.

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 per year of all criteria pollutants other than PM$_{2.5}$, and less than 0.5 tons per year of PM$_{2.5}$.

V. EXPLANTION 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 M8.

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 (SIP Only)]

SWCAA 400-052 was deleted from SWCAA 400 effective November 15, 2009, however the rule is still a part of the Washington SIP.

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, 15, 17 - 20, 23, 24, 34, 38, 39 Regulatory Order to Establish RACT**  
[SWCAA 97-2057R1]

The Regulatory Order to Establish Reasonably Available Control Technology (RACT) superseded all previous Orders applicable to EU-1 and EU-2.

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 SO₂, NOₓ, PM, and CO emissions from the plant. The Centralia Plant petitioned SWCAA for a modification of the NOₓ emission limit, and SWCAA revised the RACT Order as SWCAA 97-2057R1 on February 26, 1998. This Order establishes RACT emission limits for SO₂, NOₓ, 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 18 applies during normal operation. Emissions during startups, shutdowns, and outages of the FGD system are addressed by Requirement 19.
**Req. 16, 21, 25 Utility MACT Emission Limits**

[40 CFR 63 Subpart UUUUU]

The Utility MACT established emission limitations for hazardous air pollutants or their surrogates from coal and oil fired electric utility steam generating units.

For non-Hg hAP metals, sources may comply with an alternative particulate matter (PM) emissions limit as a surrogate. Past source emissions testing at this facility has consistently demonstrated compliance with the Utility MACT PM emission limit by a wide margin and the Utility MACT emission limit is far less stringent than the PM emission limit in RACT Order 97-2057R1, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". The Utility MACT PM emission limit and the PM emission limit in RACT Order 97-2057R1 were listed separately for informational purposes and because of the significant monitoring and recordkeeping requirements tied directly to the Utility MACT.

For HCl and HF emissions, sources may comply with an alternative SO₂ emissions limit as a surrogate. This is the choice TransAlta has chosen for the obvious reason that TransAlta already must already operate an SO₂ CEMS to comply with the Acid Rain Program, WAC 173-400, SWCAA 400, and SWCAA 97-2051R1. CEMS data for this facility indicates that this facility consistently demonstrates compliance with the Utility MACT SO₂ emission limit by a wide margin, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan".

The Hg emission limit in the Utility MACT is more stringent than the Hg emission limit TransAlta complies with under an off-permit agreement with Washington State signed May 2010. To comply with this off-permit agreement, TransAlta installed a Hg CEMS system that was certified to the Clean Air Mercury Rule standards in December 2009. TransAlta has chosen to continue use of the Hg CEMS (rather than utilize a sorbent trap monitoring system) to demonstrate compliance with the Hg emission limit. The Hg CEMS provides the real-time feedback necessary to allow TransAlta to adjust operation of the Hg control system to assure compliance with the standard. TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". For the Hg standard, sources must meet a more stringent Hg emission limit under the emissions averaging provisions.

**Req. 26 - 32 Washington Department of Ecology BART Order**

[First Revision of BART Order No. 6426]

The BART Order established NOₓ and NH₃ emission limits and associated operating, monitoring, recordkeeping, and reporting requirements for the two coal fired boilers. The BART NOₓ emission limit of 0.21 lb/MMBtu (30-day rolling average, both units averaged together) is more stringent in all aspects than the previously established RACT permit limit of 0.30 lb/MMBtu (annual average); therefore the RACT limit was not listed in the permit. In accordance with EPA guidance, the RACT citation is still included even though the requirement itself has been streamlined.
Requirement 27 states that only coal from the Powder River Basin or other coal that will achieve the same emission rates can be used. In the Technical Support Document for the BART Order (version last revised November 2011), Ecology wrote "A coal meeting the nitrogen and sulfur content of the Jacobs Ranch Upper Wyodak coal depicted in Appendix A, Table A-2 is considered to be a PRB coal or equivalent coal." Tables A-1 (containing a comparison of Centralia and PRB Coal) and A-2 are reproduced below:

### Table A-1 Summary of Key Centralia Mine and Powder River Basin Coal Characteristics

<table>
<thead>
<tr>
<th></th>
<th>TransAlta Centralia Mine Coal</th>
<th>Powder River Basin Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low Sulfur (&lt;1.2%)</td>
<td>High Sulfur (&gt;1.2%)</td>
</tr>
<tr>
<td></td>
<td>Mean</td>
<td>Max</td>
</tr>
<tr>
<td>Btu/lb</td>
<td>7,681</td>
<td>8,113</td>
</tr>
<tr>
<td>Sulfur (%)</td>
<td>0.69</td>
<td>0.84</td>
</tr>
<tr>
<td>Ash (%)</td>
<td>15.44</td>
<td>16.44</td>
</tr>
<tr>
<td>Carbon (%)</td>
<td>44.95</td>
<td>47.37</td>
</tr>
<tr>
<td>Nitrogen (%)</td>
<td>0.76</td>
<td>0.80</td>
</tr>
</tbody>
</table>

Coal characteristics on an "as received" basis.

### Table A-2 Powder River Basin Coal Characteristics, from Best Available Retrofit Technology Analysis for the Centralia Power Plant, July 2008

<table>
<thead>
<tr>
<th>Coal Sources and Characteristics</th>
<th>Units</th>
<th>Buckskin 8500</th>
<th>Caballo 8500</th>
<th>Cordero Rojo</th>
<th>Jacobs Ranch Upper Wyodak</th>
<th>Rawhide</th>
<th>Special K Fuel</th>
<th>Belle Ayr</th>
<th>Eagle Butte</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proximate Analysis (As-Received Basis)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Higher Heating Value Btu/lb</td>
<td></td>
<td>8400.00</td>
<td>8500.00</td>
<td>8456.00</td>
<td>8800.00</td>
<td>8300.00</td>
<td>7907.00</td>
<td>8500.00</td>
<td>8400.00</td>
</tr>
<tr>
<td>Moisture %</td>
<td></td>
<td>23.95</td>
<td>29.90</td>
<td>29.61</td>
<td>26.45</td>
<td>30.50</td>
<td>25.74</td>
<td>30.50</td>
<td>30.50</td>
</tr>
<tr>
<td>Volatile Matter %</td>
<td></td>
<td>30.25</td>
<td>31.40</td>
<td>30.71</td>
<td>32.50</td>
<td>30.40</td>
<td>28.76</td>
<td>30.40</td>
<td>31.92</td>
</tr>
<tr>
<td>Fixed Carbon %</td>
<td></td>
<td>34.65</td>
<td>33.80</td>
<td>34.22</td>
<td>34.35</td>
<td>34.20</td>
<td>32.46</td>
<td>34.20</td>
<td>32.93</td>
</tr>
<tr>
<td>Ash %</td>
<td></td>
<td>5.15</td>
<td>4.90</td>
<td>5.46</td>
<td>6.70</td>
<td>4.90</td>
<td>13.04</td>
<td>4.90</td>
<td>4.65</td>
</tr>
<tr>
<td>Fixed Carbon to Volatile Matter (Fuel) Ratio</td>
<td>1.15</td>
<td>1.08</td>
<td>1.11</td>
<td>1.06</td>
<td>1.13</td>
<td>1.13</td>
<td>1.12</td>
<td>1.03</td>
<td></td>
</tr>
</tbody>
</table>
Coal from outside the Powder River Basin that meets the minimum quality characteristics of the coal from Jacobs Ranch Upper Wyodak would be allowed. The Powder River Basin is a region of Montana and Wyoming with subbituminous coal characterized by low Btu, sulfur content, and ash content.
Requirement 28 was written with the understanding that direct temperature monitoring was the most appropriate method of determining when to begin and end urea injection during startup and shutdown. If urea is injected when the boiler temperature is too low, the urea will disassociate and the resulting ammonia will exit the boiler un-reacted (ammonia slip). TransAlta and the SNCR system manufacturer have indicated that routine direct temperature monitoring is not practical due to ash movements and other currents within the boiler. However, TransAlta has developed data to correlate steam flow from a particular boiler with the temperature at or near the urea injection point. This data can be used to determine what
steam flow values correlate to the appropriate temperature regimes for beginning and ending urea injection. The permit included continuous monitoring and recordkeeping of steam flow from each unit as a surrogate for direct temperature monitoring.

Requirement 29 has streamlined Section 6.2 of the First Revision of BART Order No. 6426 with Section 8.3 of the same Order. Section 6.2 described estimating ammonia between required source testing events using inputs that can be used to determine the mass injection rate of ammonia, inlet and outlet NOX, and "other parameters as necessary." Section 8.3 is more specific and states that compliance will be indicated by injecting reagent at the same relative rate as during the most recent source test and meeting the NOX emission rate. SWCAA has interpreted Section 6.2 (the less specific requirement) to be an example of "credible evidence".

Req. 22, 88 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 SO2 allowances not less than the total annual emissions in tons of SO2 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. 33 Acid Rain NOX 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. 35 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 SO2, NOX, and CO2 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. All subsequent testing has supported this determination.

**Gaseous Pollutant Monitoring at Bypass Stack**

SWCAA 97-2051R1 requires monitoring of SO₂ 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. 36 Utility MACT Tune-up Requirements**

[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires initial and periodic tune-ups of the coal-fired boilers. The tune-up requirements are detailed in 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. At the time this permit is being issued, TransAlta does not utilize neural network combustion optimization software; therefore the tune-up must be conducted every 36 months.

**Req. 37 Utility MACT Startup and Shutdown Provisions**

[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires that all startups be conducted on "clean fuels". Sources are required to use the cleanest fuel available on-site or accessible nearby during startup and shutdown when pollution control equipment is not engaged. The boilers are not designed to burn natural gas, and natural gas is not available at the boiler site, and therefore it is SWCAA's interpretation that natural gas is therefore not one of the facility's choices among "clean fuels." Unlike natural gas, different grades of liquid fuel are "accessible nearby" for the purposes of this rule. At this facility, the only available "clean fuel" is distillate oil. The requirement mentions the possibility of natural gas usage because the permittee is not precluded from considering a capital project to add natural gas firing capability. However, it is likely that New Source Review or another permitting action would be required before installing natural gas firing capability.

In the interests of streamlining the permit, the portions of the cited regulations that reference recordkeeping and reporting requirements were considered informational and not included in the permit requirement. All applicable recordkeeping and reporting requirements and included elsewhere in the permit.

Table 3 of Subpart UUUUU (as in effect 7/1/13) requires that certain air pollution control equipment (in this case the ESPs, mercury emission control system and flue gas desulfurization system) be engaged during startup when the boiler converts to firing residual
oil or coal. Because startup requirements were under reconsideration as of the time of permit issuance, only a general reference to the work practice standards of Table 3 was included. Any resulting regulatory changes or needed specificity will be reflected in a future permitting action when the reconsideration is complete.

**Req. 38 Good Air Pollution Control Practices**

[40 CFR 63.9991(c)(2), 63.1000(b), SWCAA 97-2057R1]

This requirement as it originates from SWCAA 97-2057R1 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 SO₂, NOₓ, and PM emissions from the coal-fired boilers.

**Sulfur Dioxide**

The SO₂ 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 SO₂ as low as practicable without allowing the SO₂ CEMS indication to drop to or below zero (below zero indications are possible due to minor instrument drift). A small amount of SO₂ 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 SO₂ 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, SO₂ can be maintained at a minimum level with the use of less than three recycle pumps.

In addition to maintaining minimum SO₂ 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 NOx emissions control system is good boiler combustion practices and low NOx burner modifications on the boilers. NOx control is significantly different than add-on SO2 control. NOx control is an integral part of the combustion process. If the boiler is operated to minimize NOx emissions, combustion efficiency decreases to the point of limiting electrical power output, increases coal combustion/megawatt which increases emissions of other pollutants (SO2, 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 NOx 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. 40, 41 Boiler MACT Requirements for Auxiliary Boiler
[40 CFR 63 Subpart DDDDDD]
Boilers in the "limited use" subcategory are those boilers with a federally enforceable annual average capacity factor of no more than 10 percent. The Auxiliary Boiler (EU-3) is a startup boiler; therefore a low capacity utilization would be expected. Section 45 of SWCAA 97-2057R1 expressly limited the total amount of fuel this boiler can fire to 600,000 gallons per year. The boiler has a rated heat input capacity of 170 MMBtu/hr. Assuming a fuel oil heat input capacity of 138,000 Btu/gallon (from 40 CFR 98), the 600,000 gallon per year limitation is equivalent to a capacity factor of approximately 5.6%. Both the 600,000 gallon per year limitation and the 10 percent capacity factor threshold are on a calendar year basis. Boilers in the "limited use" subcategory are subject to the general requirement to operate consistent with good air pollution control practices and the requirement to conduct initial and periodic tune-ups rather than specific emission limits.

Req. 42 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. The pug mill mixing function is conducted through the use of the two UCC Model 6050 Pin Paddle Mixers installed in 2009.

Req. 43 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. 44 - 46 Control of Particulate Matter from Coal Unloading**

[SWCAA 11-2972]

The requirements in Air Discharge Permit SWCAA 11-2972 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 11-2972) for each transfer point:

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

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. 47, 48 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. 49, 50 Control of Particulate Matter from Journal Shop**

[SWCAA 08-2779]

Air Discharge Permit SWCAA 08-2779 was written in response to an Air Discharge Permit (ADP) application for installation of a larger capacity cartridge filtration system to control welding fumes exhausted from the Journal Shop. The purpose of the project was to reduce worker exposure to welding fumes. The requirements in Air Discharge Permit were written to implement BACT and protect ambient air quality.
Req. 51 - 59, 66  Engine Requirements Originating from 40 CFR 63 Subpart ZZZZ
[40 CFR 63 Subpart ZZZZ]

40 CFR 63 Subpart ZZZZ established emission limitations and operating requirements for various categories of reciprocating engines. The engines at the coal plant fall into two categories of engines regulated by Subpart ZZZZ. All of the applicable requirements for these engines have been included in the Air Operating Permit.

One requirement requires that engines be maintained "according to the manufacturer's emission-related written instructions or develop a maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions." The permittee submitted a maintenance plan for their stationary diesel engines to SWCAA on August 8, 2011. The portions of the maintenance plan relevant to engine emissions are included in Appendix C and are applicable requirements as described in Req. 53.

Requirement 57 references emergency operation as the term is used in 40 CFR 63 Subpart ZZZZ. For the purposes of this requirement, emergency operation of a generator engine is defined as operation for the purposes of producing power for critical networks or equipment (including power supplied to portions of the facility) when electrical power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted. Stationary engines operated for the purposes of peak shaving are not considered emergency stationary engines. Stationary engines used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines except as permitted under 40 CFR 63.6640(f).

For the purposes of this requirement, emergency operation of the fire pump or emergency water pump is any operation necessary in response to a fire or flooding conditions.

Req. 60 - 66  Requirements for the Coal Unloading Facility Emergency Diesel Sump Pump Engine
[40 CFR 63 Subpart ZZZZ, 40 CFR 60 Subpart III, and SWCAA 11-2972]

The Coal Unloading Facility Emergency Diesel Sump Pump Engine was installed as a "new" engine for the purposes of 40 CFR Subpart ZZZZ, therefore the engine is required to comply with Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart III. The engine underwent New Source Review, resulting in the issuance of Air Discharge Permit 11-2972. Air Discharge Permit 11-2972 contained all of the applicable requirements from 40 CFR 60 Subpart III and additional requirements originating from SWCAA's general regulations and the minor New Source Review process.

In a June 28, 2011 amendment to 40 CFR 60 Subpart III, EPA changed section 60.4211(a) to allow owners/operators of stationary engines to deviate from manufacturer's written emissions-related instructions if they complied with additional recordkeeping and conducted an initial source test to demonstrate compliance with the applicable emission standards. These alternative requirements are included in section
60.4211(g). This compliance option is not detailed in the permit because the permittee has indicated that they will follow the manufacturer's written instructions.

For the purposes of this requirement, emergency operation is any operation necessary because the electrical water pump at the Coal Unloading Facility has unexpectedly failed. If the electrical water pump fails, it must be repaired as soon as practical. Operation of the Coal Unloading Facility Diesel Sump Pump Engine because the electrical water pump was not repaired as soon as practicable, would not be considered emergency operation.

Compliance with the annual emission limits for the Engine in Condition 5 of SWCAA 11-2972 is to be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 11-2972 unless new emission factors are provided by the manufacturer or developed through source testing.

**Req. 67 - 75 Requirements for the Non-Emergency Stationary Engines [SWCAA 12-3035]**

Air Discharge Permit 11-2996 was written to approve the Pump-05 Engine and the "grandfathered" Barge 5429 Engine. This permit was superseded by 12-3035 that approved a replacement fire pump engine. Compliance with the annual emission limits for the Pump-05 Engine in Condition 1, and the Fire Pump Engine in Condition 5 of SWCAA 12-3035 is to be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 12-3035 unless new emission factors are provided by the manufacturer or developed through source testing. These emission factors are listed in the explanation of M30.

**Req. 76 – 80 Requirements for the Material Handling Systems Associated with the Mercury Control System and Fly Ash Bins [SWCAA 11-2984]**

Air Discharge Permit 11-2984 was written to approve material handling modifications necessary to implement an activated carbon injection (ACI) mercury control system on the two coal-fired boilers. The fly ash bin baghouse exhausts will be subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64, and will each utilize a baghouse leak detection monitor. Until a CAM plan is developed, each leak detection system shall be installed, operated, and maintained in accordance with the requirements in 40 CFR 60.256(c)(1) (found in Subpart Y). This monitoring (along with periodic source emissions testing) is expected to provide an adequate assurance of compliance with the permitted emission limits. This is the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore this approach is presumed to be equivalent to CAM.

Compliance with the annual emission limits in Condition 1 of SWCAA 11-2984 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.005 gr/dscf unless new emission factors are developed through source testing.
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<tr>
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</table>

Condition 3 of SWCAA 11-2984 requires that each emission unit be operated properly. It will be presumed that the equipment is being operated properly unless otherwise indicated by an inspection or excess emissions. In that case, equipment operating manuals and maintenance records may be reviewed to determine if the equipment is being improperly operated or maintained.

**Req. 81 – 85 Requirements for the Fly Ash Weigh Bin**  
[SWCAA 12-3016]

Air Discharge Permit 12-3016 was written to approve a new baghouse for the Fly Ash Weigh Bin to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America at the time of permitting), and the relatively new "Fly Ash Bin 11 to Weigh Hopper Air Slide Filter" (operated by TransAlta). The replacement baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the #11 Air Slide and the #12 Air Slide.

Compliance with the annual emission limits in Condition 1 of SWCAA 12-3016 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.002 gr/dscf until or unless new emission factors are developed through source testing.

**Req. 86 – 93 Requirements for Fine Coal Handling**  
[SWCAA 14-3093]

Air Discharge Permit 14-3093 was written to approve coal mine waste reprocessing activities and fine coal recovery. Only fine coal handling will occur at TransAlta Centralia Generation.

Annual emissions of particulate matter from the transfer of fine coal onto the coal stockpile are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 14-3093) for each transfer point:
\[ E = k(0.0032)^{\frac{U}{5}^{1.3}} \left( \frac{M}{2} \right)^{1.4} \]

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 (%)

Meteorological data indicates that the mean wind speed at this site is 4 miles per hour. It was assumed that wet suppression will provide for 90% control of fugitive dust emissions. There is only one transfer point that is not fully enclosed (transfer to the TransAlta Generation stockpile). The transfer to the TransAlta Generation stockpile will be equipped with high-pressure wet suppression that will be used if visible emissions are observed. It is expected that the fine coal moisture will be too high to generate significant dust.

**Req. 95 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. 94, 99 (second half), 107 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.
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 Relative Accuracy Test Audit (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 24$^{th}$ hour following a unit startup.

Operation of the Black Stop Diesel Generator Engine is limited to "testing, maintenance, and use during grid-failure emergencies." The engine may be used to provide power to the facility during a maintenance event in which utility power must be disconnected, provided the duration of use does not exceed 50 hours per year in accordance with 40 CFR 63.6640(f)(2)(iii). If non-emergency operation exceeds this value, the engine is not considered an "emergency engine" for the purposes of 40 CFR 63 Subpart ZZZZ. Emergency operation includes operation during time periods in which power is shut off unilaterally by the utility.
Req. 98, 102, 103, 106, 110, 113 – 116, 121, 122  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 PM10 and NOx.

The emission limits and operating requirements in PSD-01-01 Amendment 2 represent BACT for PM10 and NOx 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 NOx emissions on a daily basis because this is the highest emission rate for which visibility modeling was performed.

Requirements 113 and 114 are not associated with specific monitoring because the annual compliance certification provides adequate assurance of continuing compliance. 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 NOx compliance plan submitted in order to certify compliance.

Requirement 114 requires submission of a NOx compliance plan. Although no time schedule is specified, it was expected that the NOx 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" was appropriate so that the operational experience gained during commissioning can be utilized to prepare the plan. An initial plan was submitted September 20, 2002.

The 3-hour average emission concentration limit specified in Req-90 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.

Req. 118 - 120 Boiler MACT Requirements for BHP Auxiliary Boiler
[40 CFR 63 Subpart DDDDD]

The BHP Auxiliary Boiler burns only natural gas and therefore is in the "Unit designed to burn gas 1" subcategory for the purposes of Subpart DDDDD. Boilers in this subcategory are not subject any emission limits or operating limits. Boilers in this subcategory are required to operate consistent with good air pollution control practices, conduct initial and periodic tune-ups, and conduct a one-time energy assessment rather than comply rather than specific emission limits.
VI. EXPLANATION OF OBSOLETE AND FUTURE REQUIREMENTS

1. Obsolete 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 SO₂ 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 SO₂ emission limit based on average daily coal sulfur analyses, and required the permittee to implement coal analysis at twenty minute intervals, perform sampling of SO₂ emissions, and correlate the sampling results with the coal analyses. The Order suspended a civil penalty provided that no additional violations of the SO₂ 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 SO₂ 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 SO₂ and O₂ 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 SO₂ emissions, and comply with the SO₂ emission limit of 1,000 ppm averaged over a one week period. This Order, issued on February 24, 1988, withdrew the coal analysis and SO₂ 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 SO₂ emission standard and established a weekly averaging period effective May 25, 1988 through November 25, 1989. SWCAA 88-934B required measured SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO₂ 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 SO₂ standard over a 1-hour averaging period. It also established a procedure for determining compliance with the hourly SO₂ standard which defined an "excess SO₂ emission day" as 3 or more unique excess SO₂ emission hours during any continuous 24-hour period in the month, and an "SO₂ emission violation" as 3 or more unique excess SO₂ emission days occurring in a
calendar month. SWCAA 97-2057R1 supersedes Order No. SWCAA 90-934E along with its SO₂ compliance procedure.

Regulatory Order to Establish RACT SWCAA 95-1787 established a plant-wide annual average emission rate limit and total tonnage limit for SO₂ 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 SO₂ 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 NOₓ). 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 Coal Unloading Facility. Air Discharge Permit 07-2749 was superseded by Air Discharge Permit 11-2972 on April 14, 2011. Air Discharge Permit 11-2972 was written in response to a request to install a diesel-fired emergency water pump at the 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% O₂ (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O₂ (1-hour average) was retained.

Best Available Retrofit Technology (BART) Order No. 6426 was issued June 18, 2010 by the Washington Department of Ecology as implementation of Washington's visibility program (WAC 173-400-151) which is implemented consistent with the federal visibility protection program (40 CFR Part 51, Subpart P). Order No. 6426 established a NOₓ emission limit of 0.24 lb/MMBtu for the coal fired boilers and a minimum coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012. Order No. 6426 was superseded by the First Revision of Order No. 6426 issued December 13, 2011. The First Revision of Order No. 6426 was issued to implement new requirements from a 2011 law (Washington Engrossed Second Substitute Senate Bill 5769). Under this law the Governor is required to enter in a "memorandum of agreement" with the plant owner on behalf of Washington State to install and operate selective non-catalytic reduction (SNCR) to provide additional control of NOₓ emissions no later than January 1, 2013. The Memorandum of Agreement was finalized December 23, 2011. The law also requires one boiler to comply with the greenhouse gas emission performance standard in RCW 80.80 by December 31, 2020 and the second boiler by December 31, 2025. These requirements were included in the First Revision of Order No. 6426. It is anticipated that compliance with the greenhouse gas standards will be accomplished by decommissioning of the units.
Air Discharge Permit 11-2996 was issued November 11, 2011 for installation and operation of the Pump-05 Engine. Air Discharge Permit 11-2996 also addressed the grandfathered engine on Barge 5429. Air Discharge Permit 11-2996 was superseded on October 18, 2012 by Air Discharge Permit 12-3035. Air Discharge Permit 12-3035 was issued for installation of a new fire pump engine that may also be used to supply non-emergency water pumping during plant maintenance events. The permit conditions related to the engines addressed in Air Discharge Permit 11-2996 were carried forward in Air Discharge Permit 12-3035.

2. Future NSPS/MACT/NESHAP Standards


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 Boiler or Process Heater" subcategory because it burns liquid fuel and fuel consumption is limited to 600,000 gallons per year (~5.6% capacity factor) by SWCAA 97-2051R1. Any boiler or process heater that has a federally enforceable average annual capacity factor of no more than 10% is in the "Limited-use boiler or process heater" subcategory. EU-12 is in the "Gas 1" subcategory because it burns only natural gas.

40 CFR 63.7491(a) exempts utility steam generating units covered by 40 CFR 63 Subpart UUUUU from regulation by Subpart DDDDD. The Unit #1 Boiler (EU-1) and Unit #2 Boiler (EU-2) are not subject to Subpart DDDDD because they are covered by Subpart UUUUU.

The effective date of the rule for existing boilers is January 31, 2016. Both EU-3 and EU-12 are existing boilers.

TransAlta submitted an initial notification for EU-3 and EU-12 under the revised rules issued January 31, 2013 in a letter to EPA Region 10 and SWCAA dated May 1, 2013.


Subpart UUUUU applies to the two coal-fired boilers (EU-1 and EU-2). The compliance date for TransAlta's coal-fired boilers is April 16, 2015. Subpart UUUUU establishes emission limits for non-Hg HAP metals, hydrogen chloride, and Hg, work practice standards, monitoring requirements and reporting requirements. TransAlta is expected to be in the subcategory of "Unit designed for coal greater than or equal to 8,300 Btu/lb" subcategory – listed as "Coal-fired unit not low rank virgin coal" in Table 2.

On April 24, 2013 EPA finalized reconsideration of a number of issues other than startup and shutdown. On June 25, 2013 EPA reopened the comment period for the proposed reconsideration to solicit additional input on specific startup and shutdown related issues.
The effective date of the rule for existing units is April 16, 2015. Both EU-1 and EU-2 are existing units.

TransAlta submitted an initial notification for EU-1 and EU-2 in a letter dated May 24, 2012.

National Emission Standards for Greenhouse Gas Emissions from Modified, Reconstructed and Existing Power Plants

On June 25, 2013 the EPA was directed by the President to propose carbon pollution standards for modified, reconstructed, and existing power plants no later than June 1, 2014 and final standards no later than June 1, 2015. The rules are to be developed under the authority of Sections 111(b) and 111(d) of the Federal Clean Air Act.

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 Coal-Fired Boiler Shutdown Requirements

Condition 4 of the First Revision of Bart Order No. 6426 requires that one coal-fired unit permanently cease burning coal no later than December 31, 2020, and the second permanently cease burning coal no later than December 31, 2025. These requirements would not apply if the Department of Ecology determines as a requirement of state or federal law or regulation that selective catalytic reduction (SCR) technology must be installed on either coal fired boiler. This requirement implements requirements in RCW 80.80 as amended in 2011. RCW 80.80 requires that the coal fired boilers meet a greenhouse gas performance standard of 1,100 lb/MW-hr on the dates listed above unless SCR installation is required by law or regulation. The 1,100 lb/MW-hr emission standard cannot be met by these boilers without the addition of CO₂ capture equipment or shutdown.
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 and specific requirements drawn from SWCAA 01-2350R4, SWCAA 05-2636, SWCAA 11-2972, and SWCAA 12-3016. 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 8 of Air Discharge Permit SWCAA 11-2972 requires that the water pressure of the spray/fog nozzles be maintained at 80 psig or greater during operation of the coal unloading facility, 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, SWCAA 400 and specific requirements in SWCAA 01-2350R4, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 12-3035. WAC 173-400, SWCAA 400, SWCAA 01-2350R4, Condition 3 of SWCAA 12-3016, and SWCAA 12-3035 do not directly establish any specific regime of monitoring or recordkeeping for these requirements. Consequently, for these rules 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 SO₂ General Standard Monitoring

This monitoring requirement in combination with M8 is used to provide a reasonable assurance of compliance with the general SO₂ emission concentration limit contained in WAC 173-400 and SWCAA 400. WAC 173-400-040(7) 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 SO₂ concentrations of the flue gasses emitted by EU-1 and EU-2 and determines 60-minute averages (see M8).

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 SO₂ concentration relies upon an approximate linear relationship based on operational experience with a coal sulfur content of 1% by weight corresponding to an SO₂ 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:

\[
ppm\text{SO}_2@7\%O_2 = \frac{7.206\text{lb oil}}{\text{gallon}} \cdot \frac{1\text{gallon}}{0.141\text{MMBtu}} \cdot \frac{0.005\text{lb S}}{\text{lb \cdot mole}} \cdot \frac{385\text{scf}}{\text{lb \cdot mole}} \cdot \frac{\text{MMBtu}}{9,190\text{dscf}} \cdot \frac{(20.9-7\%O_2)}{10^6}
\]

\[
ppm\text{SO}_2@7\%O_2 = 22.2
\]
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, the specific emission limits contained in SWCAA 97-2057R1, First Revision of BART Order No. 6426 and 40 CFR 63 Subpart UUUUU. 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 NOX, CO, particulate matter, SO2, 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 NOX and SO2 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 SO2, NOX, 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.

Ammonia slip monitoring must be conducted at least annually, and as frequently as quarterly in accordance with the requirements of the First Revision of BART Order No. 6426. Between source emission tests, urea usage is monitored in accordance with M28. Large increases in urea usage without corresponding decreases in NOX emissions would indicate the possibility of increased ammonia slip.

Sources may comply with the initial performance test required by Subpart UUUUU through source testing for individual pollutants or surrogates, or submitting 30 boiler operating days of data collected immediately before or after then effective date of April 16, 2015 with the certified monitoring system. Because TransAlta has chosen to utilize CEMS to demonstrate continuous compliance with the PM, SO2 and Hg standards, the CEMS must also be used for the initial performance testing in accordance with 40 CFR 63.10007(a)(1).


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, First Revision of BART Order No. 6426, 40 CFR 63 Subpart UUUUU, and to provide compliance with the Acid Rain requirements.
CEMS for SO₂, NOₓ, CO, CO₂, Hg, and moisture monitor exhaust concentrations and allow for the calculation of mass emission rates of these pollutants from the coal-fired boilers. A COMS for measuring the opacity of emissions has been 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. Note that TransAlta received an official exemption from the Acid Rain Program COMS requirements for the scrubbed stacks in accordance with 40 CFR 75.14(b) [see letter from Sam Napolitano (EPA) to Lou Florence (TransAlta) dated July 28, 2011]. SWCAA 97-2057R1 requires the use of an SO₂/O₂ CEMS on the bypass stacks. NOₓ and CO₂ 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 O₂ monitor measures and records O₂ concentration in the stack gas discharged to the atmosphere consistent with the Acid Rain monitoring provisions, although the requirement for operating an O₂ monitor is based on SWCAA 97-2057R1, Sections 21 and 27a, WAC 173-400-040(7) and 173-400-050(3), and SWCAA 400-040(6) and 400-050(3) which specify that the 1-hour average SO₂ concentration data be on a dry basis corrected to 7% O₂. The correction method uses the as-measured SO₂ concentration for each clock hour and the corresponding actual O₂ concentration to standardize the SO₂ data to 7% O₂, as shown:

\[ \text{SO}_2, \text{dry @ 7\% O}_2 = \left[ \frac{20.9 - 7}{20.9 - \text{O}_2\%, \text{dry}} \right] \times \text{SO}_2, \text{dry @ actual O}_2\% \]

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 and Subpart UUUUU as applicable. WAC 173-400-040 does not directly establish any specific regime of continuous monitoring or recordkeeping for 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 M8(c) 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 SO₂ 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 state and local rules and permits, 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 SO₂ concentrations.

Missing data substitution procedures of 40 CFR 75 are not utilized to demonstrate compliance with the NOₓ emission limit from the First Revision of BART Order No. 6426 or the SO₂, PM, or Hg emission limits from 40 CFR 63 Subpart UUUUU. Reported emissions for comparison with these limits are intended to be more representative of actual emissions than the more conservative reporting required by 40 CFR 75 (Acid Rain Program Monitoring).

Electric output monitoring was added under the "gap filling" provisions of WAC 173-401-615 in order to allow the calculation of SO₂, PM, and Hg emission rates in units of lb/MWh or lb/GWh for comparison with the emission limits in 40 CFR 63 Subpart UUUUU.

Section (k)(2) includes the requirement from 40 CFR 63 Subpart UUUUU to conduct particulate matter testing 80 to 100 calendar days after the previous quarterly test, with some exceptions. No provisions are made in the rule for circumstances when the affected unit is offline during that timeframe. This facility, and other thermal plants in the region, is normally offline for significant periods of time during the spring when hydropower is abundant. The CEMS monitoring provisions of 40 CFR 63 Subpart UUUUU and the limitation of particulate matter testing to quarters with at least 168 hours of operation is consistent with the Acid Rain Program monitoring requirements of 40 CFR 75. Consistent with these requirements SWCAA believes it is appropriate to treat quarterly tests as RATAs for scheduling purposes, so that tests normally due during offline periods must be completed within 720 hours or re-starting the affected unit.

**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.

M9 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 SO₂ emissions during shutdown, startup, and maintenance of the SO₂ emission control technology in excess of 250 ppm are excused under WAC 173-400-107 and SWCAA 400-107 provided the alternative hourly SO₂ 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 SO₂ emission control technology when the ESPs are off line and not removing PM is expected to foul or possibly plug key components, so the SO₂ 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 SO₂ limit and the alternative shutdown, startup, and SO₂ 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 SO₂ 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 SO₂ 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 SO2 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 SO2 emitted for comparison with the limitations shall include all hourly SO2 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 SO2 emissions exceed the tons per year SO2 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 SO2 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 SO2 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 SO2 emission control technology provided it met the SO2 emission requirements specified in Requirements 16 and 19. In addition, the Centralia Plant owners had sole discretion to select the NOX emission control technology provided it satisfied Requirements 25 and 26 (Req-26 contained an interim NOX emission limit). The control technology configuration could include the maintenance of the original stacks for bypass provided a CEMS was maintained to monitor SO2 emissions from the bypass stacks.

If the bypass stacks do not contain certified functional CEMS for SO2, any emergency bypass emissions released through these stacks will be considered an upset condition reportable to SWCAA as a deviation from permit conditions. All SO2 emissions released from the facility, regardless of where, how, or under what operating condition, is included in the plant SO2 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 and the fuel usage monitoring requirement of 40 CFR 63.7525(k). 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\textsubscript{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\textsubscript{2} emission calculation using the maximum allowed annual fuel consumption is shown below:

\[
\frac{600,000 \text{ gallons}}{\text{year}} \times \frac{7.206 \text{ lb oil}}{\text{gallon}} \times \frac{0.005 \text{ lb S}}{\text{lb oil}} \times \frac{1 \text{ lb-mole S}}{32 \text{ lb S}} \times \frac{64 \text{ lbs SO}_2}{1 \text{ lb-mole SO}_2} \times \frac{1 \text{ ton}}{2,000 \text{ lbs}} = 21.6 \text{ tons per year}
\]

The daily fuel monitoring requirement of 40 CFR 63.7525(k) is used to demonstrate that the boiler remains in the "limited use" subcategory and is exempt from many of the requirements of 40 CFR 63 Subpart DDDDD.

**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\textsubscript{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\textsubscript{x}, CO, and NH\textsubscript{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\textsubscript{x} and CO emissions will come from the turbines, and because periodic source testing will be conducted to quantify NO\textsubscript{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\textsubscript{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 NOX 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 NOX, CO, PM, NH3, 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. NOX, CO, and NH3 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 NOX 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 start up 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 NOX 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).


This monitoring requirement is used to provide, in combination with fuel flow monitoring requirements, a reasonable assurance of compliance with the hourly and annual SO2 emission limits contained in SWCAA 01-2350R4. In addition, M17 provides compliance with the Acid Rain and NSPS Subpart GG monitoring requirements. SO2 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 SO2 can be calculated using a mass balance approach.

\[
SO_2 \text{ (lb/hr)} = (\text{fuel flow (lb/hr)}) \times (\text{fuel S concentration (weight fraction)}) \times \left( \frac{64 \text{ lb SO}_2}{32 \text{ lb S}} \right)
\]

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 NOₓ Control System Testing**

This monitoring requirement is used to provide, in combination with continuous NOₓ and NH₃ emissions monitoring, a reasonable assurance of compliance with the requirement in SWCAA 01-2350R4 to control NOₓ 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 NOₓ 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 NOₓ 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.


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.

Typically fuel is supplied by the refineries to local distributors and then to the ultimate users. Certification by the local fuel distributors of fuel sulfur content based on a periodic analysis of bulk fuel tanks would satisfy this requirement.

**M20. Black Stop Diesel Generator Engine Hours Monitoring**

The monthly data logging 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, NOₓ, and PM will be calculated using the hourly emission factors from the most recent source test. Emissions of VOCs and SO₂ 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.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon monoxide</td>
<td>source test</td>
<td>source test data (lb/hr) multiplied by hours/year</td>
</tr>
<tr>
<td>Nitrogen oxides</td>
<td>source test</td>
<td>source test data (lb/hr) multiplied by hours/year</td>
</tr>
<tr>
<td>PM/PM₁₀/PM₂.₅</td>
<td>source test</td>
<td>source test data (lb/hr) multiplied by hours/year</td>
</tr>
<tr>
<td>Volatile organic compounds</td>
<td>1.3 lb/hr</td>
<td>1.3 lb/hr multiplied by hours/year</td>
</tr>
<tr>
<td>Sulfur dioxide</td>
<td>0.52 lb/hr</td>
<td>0.52 lb/hr multiplied by hours/year</td>
</tr>
</tbody>
</table>

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.

To assure that the engine meets the definition and requirements for an existing emergency engine with a site rating of more than 500 horsepower located at a major source of HAPs, the Permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours were spent for non-emergency operation. This monitoring requirement was added under the "gap filling" provisions of WAC 173-401-615.

**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, NOₓ, and PM will be calculated using emission factors (in units of lb/MMscf) from the most recent source test. Emissions of SO₂ 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.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Hourly</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon monoxide</td>
<td>source test</td>
<td>source test data (lb/MMscf) multiplied by MMscf/yr</td>
</tr>
<tr>
<td>Nitrogen oxides</td>
<td>source test</td>
<td>source test data (lb/MMscf) multiplied by MMscf/yr</td>
</tr>
<tr>
<td>PM/PM₁₀/PM₂.₅</td>
<td>source test</td>
<td>source test data (lb/MMscf) multiplied by MMscf/yr</td>
</tr>
<tr>
<td>VOCs</td>
<td>5.5 lb/MMscf multiplied by fuel consumption</td>
<td>mass balance (fuel sulfur content * by fuel use)</td>
</tr>
<tr>
<td>Sulfur dioxide</td>
<td>mass balance</td>
<td>mass balance (fuel sulfur content * by fuel use)</td>
</tr>
</tbody>
</table>

Permit No. SW98-8-R4    Page 68    Issued September 16, 2014
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 performed 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 in 2004. 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\textsubscript{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 \textasciitilde 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\textsubscript{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 Facility

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.

M27. BART Order Coal Sampling and Analysis Requirements

The monitoring requirements in M27 come directly from the First Revision of BART Order No. 6426. The coal quality monitoring is used to assure that coal quality is representative of the Powder River Basin Coal used as a basis for the BART determination.

M28. BART Order Coal Sampling and Analysis Requirements

Section 1.2 of the First Revision of BART Order No. 6426 requires that urea be injected whenever it would be useful to reduce NOX emissions without generating excessive ammonia slip. Startups and shutdowns generally take many hours to complete, therefore hourly monitoring of urea flow and steam flow (as an indication of temperature conditions within the boilers) will provide adequate resolution to demonstrate compliance with this requirement. The First Revision of BART Order No. 6426 also requires that ammonia emissions be estimated between source testing events using the urea injection rate and other process data. The only process data useful to this determination that are not otherwise required to be monitored and recorded are the urea flow and steam flow required by this monitoring requirement. Urea injection rate an steam generation rate are not required by the First Revision of BART Order No. 6426; therefore these provisions were added under the "gap filling" monitoring provisions of WAC 173-401-615(1).
M29. Coal Plant Emergency Engine Monitoring

The monitoring requirements in M29 come directly from 40 CFR 63 Subpart ZZZZ as it applies to the emergency engines at the coal plant that are not subject to 40 CFR 60 Subpart IIII. For the purposes of Subpart ZZZZ, the engines are all classified as existing emergency compression ignition engines with a site rating of less than 500 horsepower. For this classification of engine, the applicable requirements are all operating or maintenance requirements. In addition, the permittee must document how many hours each engine is operated, and for what purpose it was operated, to demonstrate that the engines are indeed being operated as emergency engines. Because all operating and maintenance activities must be documented, and all operating hours accounted for, these monitoring provisions provide a reasonable assurance of compliance with the applicable requirements. A review of the documentation for a specific engine will conclusively determine the compliance status of the unit with respect to the operating and maintenance requirements.

M30. Coal Plant Non-Emergency Engine Monitoring

M30(a) comes directly from SWCAA 12-3035 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M30(b) comes directly from SWCAA 12-3035 and provides a reasonable assurance of compliance with the hours limitations for the Pump-05 engine and the Fire Pump Engine and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 12-3035 (October 18, 2012), the following emission factors are to be used:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Pump-05 Engine Emission Factors (lb/hr)</th>
<th>Fire Pump Engine Emission Factors (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOX</td>
<td>1.38</td>
<td>0.28</td>
</tr>
<tr>
<td>CO</td>
<td>0.17</td>
<td>0.14</td>
</tr>
<tr>
<td>PM</td>
<td>0.053</td>
<td>0.013</td>
</tr>
<tr>
<td>PM_{10}</td>
<td>0.053</td>
<td>0.013</td>
</tr>
<tr>
<td>PM_{2.5}</td>
<td>0.053</td>
<td>0.013</td>
</tr>
</tbody>
</table>

M30(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 63 Subpart ZZZZ. Subpart ZZZZ requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated), but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the permittee or the inspector can compare the hour meter
reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

M31. **Subpart ZZZZ Performance Testing Requirements**

This monitoring requirement consists of applicable requirements found in 40 CFR 60 Subpart ZZZZ. Only the engine category subject to numerical emissions limits requires performance testing. For the Barge 5429 Engine only an initial performance test is required by Subpart ZZZZ. EPA determined that subsequent performance testing was not justified for engines of this size in the rule to demonstrate compliance with the numerical emission limits in this size category. Subsequent performance testing is required only if engines are rebuilt or overhauled, or if an exhaust catalyst is replaced because these activities can affect the emission rates from the engine. In EPA's February 17, 2010 response to comments on proposed revisions to Subpart ZZZZ, EPA wrote:

"EPA believes that it is appropriate to require testing for stationary engines that have been rebuilt or overhauled even though the engines may only normally be required to conduct an initial performance test and no subsequent testing. The rebuilding or overhaul of the engine may change the combustion characteristics of the engine."

In a separate section EPA wrote:

"As the commenters noted, the rule does not specify a time for conducting a performance test after a catalyst change. However, the performance test after a catalyst change should be conducted as soon as possible to demonstrate that the engine is still in compliance with the applicable standards."

40 CFR 63 Subpart ZZZZ requires only an initial performance test for existing non-emergency compression ignition engines ≤ 500 horsepower, because subsequent testing was not considered worthwhile for engines in this size category. For larger engines, performance tests must be completed every 3 years or 8,760 hours of operation, whichever comes first. It appears that EPA has determined that this testing frequency is adequate to provide a reasonable assurance of compliance with more stringent limitations on > 500 horsepower engines. SWCAA added periodic testing of Barge 5429 Engine as required by the "gap filling" provisions of WAC 173-401-615 because combustion characteristics could change with usage and no other surrogate measure of compliance was available. Because operating hours are being monitored, SWCAA chose the more flexible option of testing each applicable engine at least once every 8,760 hours of operation without including the 3 year deadline. SWCAA does not expect that combustion characteristics will degrade significantly when the engines are not operating.

M32. **Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring**

M32(a) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.
M30(b) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 11-2972 (April 14, 2011), the following emission factors are to be used:

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Factors (lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{X}</td>
<td>2.54</td>
</tr>
<tr>
<td>CO</td>
<td>0.44</td>
</tr>
<tr>
<td>PM</td>
<td>0.055</td>
</tr>
<tr>
<td>PM\textsubscript{10}</td>
<td>0.055</td>
</tr>
<tr>
<td>PM\textsubscript{2.5}</td>
<td>0.055</td>
</tr>
</tbody>
</table>

M30(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 60 Subpart III. Subpart III requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated), but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

This documentation can be compared with the written maintenance instructions provided or approved by the manufacturer to determine the status of compliance with this requirement.

**M33. Mercury Control System and Fly Ash Material Handling**

The number of hours each unit is operated must be logged to allow for the calculation of annual emissions. Annual emissions must be calculated using the emission factors shown below unless new emission factors are developed through source testing.
<table>
<thead>
<tr>
<th>Filter</th>
<th>(lb/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SEA System #1</td>
<td>0.048</td>
</tr>
<tr>
<td>SEA System #2</td>
<td>0.048</td>
</tr>
<tr>
<td>Sorbent Silo #1</td>
<td>0.015</td>
</tr>
<tr>
<td>Sorbent Silo #2</td>
<td>0.015</td>
</tr>
<tr>
<td>Fly Ash Bin 11</td>
<td>0.63</td>
</tr>
<tr>
<td>Fly Ash Bin 12</td>
<td>0.63</td>
</tr>
<tr>
<td>Fly Ash Bin 14</td>
<td>0.63</td>
</tr>
<tr>
<td>Fly Ash Bin 14 Air Slide to Bin 11 Air Slide</td>
<td>0.039</td>
</tr>
<tr>
<td>Fly Ash Bin 11 to Weigh Hopper Air Slide</td>
<td>0.039</td>
</tr>
<tr>
<td>Fly Ash Bin 14 to 6050 Air Slide</td>
<td>0.026</td>
</tr>
</tbody>
</table>

The above emission rates listed in the table above are based on the design flow rate for each unit and the permitted emission concentration (0.005 gr/dscf).

**M34. Fly Ash Baghouses - Source Emission Testing Requirements**

Initially, periodic source emissions testing was coupled with the use of a baghouse leak detection system to provide a reasonable assurance with the permitted emission limits. This was the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore this approach was presumed to be equivalent to CAM. A CAM Plan was later developed for these baghouses in accordance with 40 CFR 64 and is included as M34. The CAM Plan replaced the previous requirement to operate the baghouse leak detectors in accordance with the requirements in 40 CFR 62.256(c).

The initial alarm setpoints of 100 pA were established based on the results of source emissions testing conducted October 2011 during which the following results were obtained:

<table>
<thead>
<tr>
<th>Baghouse</th>
<th>Bin 11</th>
<th>Bin 12</th>
<th>Bin 14</th>
</tr>
</thead>
<tbody>
<tr>
<td>Filterable PM</td>
<td>0.0001 gr/dscf</td>
<td>0.0002 gr/dscf</td>
<td>0.0001 gr/dscf</td>
</tr>
<tr>
<td>Leak Detector Output</td>
<td>23 pA</td>
<td>18 pA</td>
<td>42 pA</td>
</tr>
</tbody>
</table>

The system utilizes a Tribo-Flow model 4001-1111-01-154N detector. Manufacturer literature indicates that the equipment is designed for a detection limit on the order of 0.0005 gr/dscf; therefore the instrument response during the initial testing appears to be a low baseline. The 100 pA alarm setpoint is significantly less than 10 times this baseline for all stacks and well below the response expected at a concentration of 0.005 gr/dscf (the permit limit).

**M35. Fly Ash Bin Baghouses – Compliance Assurance Monitoring**

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-23, EU-24, and EU-25 in accordance with 40 CFR 64 for the permit renewal in 2014. CAM is applicable to these units because
uncontrolled PM emissions would be expected to exceed 100 tons per year each. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes an electrostatic particle detection system (also known as a baghouse leak detection system) as a surrogate indicator of particulate matter control device operation and particulate matter emissions.

During initial source emissions testing in October 2011, emissions from the baghouses were measured at 0.0001 – 0.0002 gr/dscf. This level is generally at the method detection limit and 25-50 times lower than the applicable emission limit of 0.005 gr/dscf. During the testing the electrostatic particle detector readings were 18 – 42 pA. Based on this testing, TransAlta's initial alarm setpoint of 100 pA was sufficiently protective of the permit limit that no additional testing was necessary to establish an appropriate upper limit to the indicator range.

Alarm setpoints for these types of detectors may need to be adjusted from time to time due to changes in stack conditions, ambient conditions, or detector replacements. Where such detectors are referenced in NSPS/MACT regulations (e.g. 40 CFR 60 Subpart Y, 40 CFR 63 Subpart SSSSSS), sources are allowed to change the alarm setpoints quarterly in accordance with their site-specific monitoring plan. TransAlta's CAM plan (analogous to a site specific monitoring plan under NSPS/MACT regulations) indicates that changes to the alarm setpoint would be based upon the results of source emissions testing. SWCAA incorporated this provision into the Permit.

M36. SNCR Optimization

SNCR optimization is a requirement of the First Revision of BART Order No. 6426, and no other requirement relies upon it at a compliance demonstration method. This optimization is a one-time requirement that is scheduled to be complete by the end of 2014. This requirement was listed as M36 because the optimization primarily involves monitoring of emissions as they relate to boiler and SNCR control system operation.

M37. Coal-Fired Boilers Tune-up and Startup/Shutdown Monitoring

40 CFR 63 Subpart UUUUUU requires periodic tune-ups in accordance with specific requirements. In addition, all "applicable control technologies" must be engaged when firing anything other than "clean fuels". In this case, the only other fuel is coal.

A semi-annual compliance report must be submitted that includes the date of the most recent tune-up and a report if there were any deviations from the work practice standards (consisting of the tune-up and the startup and shutdown provision). 40 CFR 63.10032(a)(1) requires sources to maintain all documentation supporting each semi-annual report. M37 describes this documentation as it pertains to the work practice standards (tune-ups and startup/shutdown provisions).

Full documentation of each tune-up as required by M37(a) provides all of the records necessary to determine if all the tune-up requirements are being met.

The information in M37(b) is necessary to determine:
a. That "clean fuels" are being burned during startup;
b. When the unit is in startup or shutdown because the emission limits from Subpart UUUUU do not apply during startup or shutdown; and
c. That the relevant emission control equipment is being engaged when required.

M38. Auxiliary Boiler and BHP Auxiliary Boiler Tune-up Monitoring

40 CFR 63 Subpart DDDDD requires periodic tune-ups in accordance with specific requirements. The initial tune-up must be fully documented in to comply with 40 CFR 63.7555(a)(1), but there is no specific requirement to fully document subsequent tune-ups. Consequently, SWCAA has implemented this documentation requirement for subsequent tune-ups under the "gap filling" provisions of WAC 173-401-615.

Full documentation of each tune-up as required by M38 provides all of the records necessary to determine if all the tune-up requirements are being met.

M39. Fine Coal Handling

The requirements listed this monitoring condition are all included in both 40 CFR 60 Subpart Y and SWCAA 14-3093. Because the permittee has not committed to a single monitoring strategy, both of the allowable strategies were included. The total amount of coal transferred is required by Subpart Y and necessary to calculate annual emissions.

VIII. EXPLANATION OF RECORDKEEPING TERMS AND CONDITIONS

K1. Basic Recordkeeping

This recordkeeping section is taken directly from SWCAA 97-2057R2 Sections 26 and 29, SWCAA 05-2636, SWCAA 08-2779, SWCAA 11-2072, 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 SO2 emission control equipment, and "upset conditions" are limited to pollution control equipment or equipment that would directly impact SO2 emissions.

K2. Acid Rain, RACT, and NSR CEMS 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, SWCAA 01-2350R4 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 SO2 standard concentrations (dry @ 7% O2) 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 SO₂ emissions from Acid Rain affected units. The data recordkeeping requirements pursuant to SWCAA 97-2057R1 for 1-hour SO₂ standard concentration (dry @ 7% O₂) 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 SO₂ 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 NOₓ 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 Dd)**

This recordkeeping requirement originates from 40 CFR 60.49b (Subpart Dd) 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 NOₓ standards of 40 CFR 60.44b(a)(4) (for duct burners in combined cycle systems) is not required to install or operate a CEMS.

K4. **40 CFR 63 Subpart DDDDD Recordkeeping**

This recordkeeping requirement is taken directly from 40 CFR 63.7555 and 40 CFR 63.7560.

K5. **40 CFR 63 Subpart ZZZZZ Recordkeeping**

This recordkeeping requirement is taken directly from 40 CFR 63.6655 and 40 CFR 63.6660. The recordkeeping requirements from 40 CFR 63.6655(e) and (f) are found in M29 rather than here because they are the direct compliance demonstration for several of the Operating Terms and Conditions.

K6. **40 CFR 63 Subpart UUUUU Recordkeeping**

This recordkeeping requirement is taken directly from 40 CFR 63 Subpart UUUUU and the general requirements of 40 CFR 63.8 and 40 CFR 63.10 that apply to Subpart UUUUU.
K7. 40 CFR 60 Subpart Y Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 60 Subpart Y. The amount of coal processed will be the amount of coal conveyed to the permittee's facility and used to calculate annual emissions.

IX. EXPLANATION OF SELECTED REPORTING TERMS AND CONDITIONS

R1. Deviations from Permit Conditions and CAM Excursions

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 PSD-01-01 Amendment 2 Condition 22(d)(1), First Revision of BART Order No. 6426 Section 11, SWCAA 97-2057/R1 Sections 23, 28, 29, and 37, SWCAA 01-2403 Section 11(e)(1), SWCAA 01-2350/R4 Conditions 28(a & b), SWCAA 11-2984 Conditions 15 and 16, and SWCAA 12-3035 Conditions 13 and 14. 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 SO₂, 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 SO₂ 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 provide a 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 40 CFR 63 Subpart UUUU, the First Revision of BART Order No. 6426, SWCAA 97-2057/R1 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 01-2350/R4 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).
For Subpart UUUUU reports, no special SO₂ CEMS data reporting are listed because reporting of SO₂ data (and supporting diluent and/or moisture monitors) is covered by the Acid Rain Program reporting requirements (see the Acid Rain Permit and 40 CFR 75). EPA guidance indicates that Acid Rain Program requirements must not be detailed in Title V permits. The Acid Rain Permit incorporates the appropriate requirements by reference. The Hg CEMS reporting requirements mirror the Acid Rain Program reporting requirements for SO₂ and require utilization of the same data reporting system. SWCAA will have access to the data through EPA's system upon submission.

WAC 173-400-105(7) establishes minimum requirements for CEMS required by an order, PSD permit or regulation and not subject to CEMS performance specifications and data recovery requirements imposed by 40 CFR 60, 61, 62, 63 or 75. The CO and NH₃ CEMS at the Combustion Turbine Facility (EU-7, EU-8, EU-9, and EU-10) are the only CEMS subject to this requirement. An explanation of any missing NOₓ CEMS data is already required by PSD-01-01 Amendment 2. Extending this to the CO and NH₃ CEMS covers the requirement to report the cause of each failure to achieve 90% data availability on a daily basis or 95% data availability on a monthly basis. The only other reporting requirement not already required by PSD-10-01 Amendment 2 or SWCAA 01-2350R4 is the requirement to report any actions taken to ensure the 95% data availability requirement is met. This requirement was added to R3.

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, including Acid Rain Program requirements. Since 2005, a separate Acid Rain Program certification has not been required.

All of the items other than the compliance certification are used to calculate annual emissions from individual emission units.

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 Plans and 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.


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. BART Order Milestone Reports

This reporting section is taken directly from the First Revision of BART Order No. 6426. The remaining milestones listed in R11 are listed here in case they are achieved early (during the 2014 – 2019 permit term).

R10. 40 CFR 63 Subpart DDDDD Reports

This reporting section is taken from 40 CFR 63.7545(e) and 40 CFR 63.9. The Notification of Compliance Status must include an identification of which category each boiler is in for the purposes of 40 CFR 63 Subpart DDDDD. The Auxiliary Boiler (EU-3) is in the "Limited Use Boiler" subcategory. The BHP Auxiliary Boiler (EU-12) is in the "Unit Designed to Burn Gas 1" subcategory.

40 CFR 63.7545(e) requires that the Notice of Compliance Status must be submitted before the close of business on the 60th day following completion of all performance test and/or other initial compliance demonstrations. From the fact that no alternative date is provided for sources not required to conduct emission or fuel testing and from reading EPA's "Small Entity Compliance Guide for Major Source Boilers and Process Heaters" SWCAA has concluded that the initial tune-ups and the one-time energy assessment for the BHP Auxiliary Boiler are applicable "compliance demonstrations" for the purposes of this rule.

R11. 40 CFR 63 Subpart UUUUU Reports

This reporting section is taken from 40 CFR 63 Subpart UUUUU and includes all reports not required to be submitted each quarter or semi-annually.
**R12. 40 CFR 63 Subpart Y Reports**

This reporting section is taken from 40 CFR 63 Subpart Y and applies to the periodic visible emission evaluation reports required by Subpart Y.

**X. COMPLIANCE HISTORY**

The following Notices of Violation (NOV) or Notice of Correction (NOC) were issued during the last permit term (September 16, 2009 to present).

<table>
<thead>
<tr>
<th>NOC/NOV#</th>
<th>Violation Date</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>4605</td>
<td>10/7/2009</td>
<td>Late submittal of second quarter 2009 reports. TransAlta replaced the CEMS at the Flue Gas Desulfurization (FGD) stacks for both units during this quarter. The submittal delay was due at least in part to the fact that the data acquisition and handling system was not set up correctly by TransAlta's contractor for the concurrent changes to EPA's submission system. Raw CEM data was available to SWCAA upon request.</td>
</tr>
<tr>
<td>4607</td>
<td>10/28/2009</td>
<td>Late submittal of four startup/shutdown event reports for events occurring between August 15 and October 26, 2009.</td>
</tr>
<tr>
<td>4610</td>
<td>2/19/2010</td>
<td>Exceedance of opacity limit for EU-1 during startup on February 14, 2010 due to operators deviating from the normal startup protocol. Operators brought the ESPs on-line early, resulting in an official closure of the &quot;startup window&quot;, but before the ESPs were warm enough to operate at full capacity and adequately control emissions during further load ramping. Placing the ESPs on-line early can result in reduce emissions during the startup event but can be detrimental to long-term performance and therefore can result in increased emissions in the long term.</td>
</tr>
<tr>
<td>4612</td>
<td>9/9/2010</td>
<td>Excess opacity by EU-2 August 13, 2010 when a combination of equipment failures and an operator mistake in response to the failures led to a bypass of the flue-gas desulfurization system and excess opacity was measured on the bypass stack due to the re-entrainment of fly ash settled in the bypass ductwork.</td>
</tr>
<tr>
<td>4618</td>
<td>4/20/2011</td>
<td>Excess opacity by EU-2 during a March 2/3, 2011 startup. The excess opacity was caused by the delay placing the flue gas desulfurization system into service when a broken cooling water return line was found shortly after starting the Water Wash System. During a normal startup, any excess fly ash downstream of the ESPs during load ramping would have been captured by the flue gas desulfurization system.</td>
</tr>
<tr>
<td>4622</td>
<td>10/18/2011</td>
<td>Exceedance of the particulate matter emission limit for EU-1 due to excessive foaming in the scrubber vessel (above the demister). The problem was not immediately noticed and corrected because an overflow line used to gage foaming was blocked.</td>
</tr>
<tr>
<td>NOC/NOV#</td>
<td>Violation Date</td>
<td>Notes</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>4644</td>
<td>6/14/2013</td>
<td>Linearity checks for NOX, SO2, and diluent CEMS were 8 days late (and 1 day beyond the 40 CFR 75 grace period) due to an oversight by TransAlta personnel.</td>
</tr>
</tbody>
</table>

**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.

Appendix C contains TransAlta's Small Engine Maintenance Plan used to meet the maintenance requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

Appendix D applies to ammonia slip testing required by the First Revision of BART Order No. 6426. Appendix D contains the Washington Department of Ecology's interpretation of acceptable ammonia slip testing schedules when limited operation interferes with a regular testing schedule.

**XII. PERMIT ACTIONS**

**Air Operating Permit SW98-8 (original Title 5 permit)**
1. Final Permit Issued: August 6, 1999

**Air Operating Permit SW98-8-R1 (administrative permit amendment)**
1. Final Permit Issued: July 12, 2000

**Air Operating Permit SW98-8-R2 (first renewal)**
1. Final Permit Issued: August 6, 2004

**Air Operating Permit SW98-8-R2-A (modification)**
1. Final Permit Issued: May 12, 2005
TransAlta - Centralia Plant

**Air Operating Permit SW98-8-R2-B (modification)**
1. Final Permit Issued: March 25, 2008

**Air Operating Permit SW98-8-R3 (second renewal)**
1. Renewal Permit Application Submitted: February 3, 2009
2. Permit Application Deemed Complete: March 17, 2009
3. Permit Application Sent to EPA: May 15, 2009
4. Draft Permit Issued: May 15, 2009
5. Proposed Permit Issued: July 21, 2009
6. Final Permit Issued: September 16, 2009

**Air Operating Permit SW98-8-R3-A (modification)**
1. "Reopening for Cause" Letter to Permttee: July 12, 2011
2. Draft Permit Issued: September 14, 2011
3. Proposed Permit Issued: October 26, 2011
4. Final Permit Issued: December 21, 2011

**Air Operating Permit SW98-8-R4 (third renewal)**
1. Renewal Permit Application Submitted: September 16, 2013
2. Permit Application Deemed Complete: January 8, 2014
3. Permit Application Sent to EPA: January 8, 2014
4. Draft Permit Issued: June 6, 2014
5. Proposed Permit Issued: July 16, 2014
6. Final Permit Issued: September 16, 2014

**XIII. PLANT DRAWINGS**
Drawing #1 - Combustion Turbine Facility Flow Diagram

- Natural gas pipeline
- Auxiliary boiler
- Stack Exhusts
- Combustion Turbines
- Duct Burners
- Heat Recovery Steam Generators
- SCR

Electricity

- 30
- 40
- 50
- 60

Steam Turbine

- 70

Diesel Black Stop Generator

Diesel tank
TransAlta Centralia Forced Oxidized Limestone FGD System

- Limestone slurry scrubbing absorbs SO₂ to form CaSO₄
- Water mist eliminators washed with fresh water
- Slurry re-circulated to 4 spray levels
- Slurry withdrawn to remove gypsum
- Aeration oxidizes CaSO₄ to form crystallized CaSO₄·2H₂O (gypsum)
- Chloride bleed to Brine Concentrator
- Hydroclone
- Gypsum solids to Filtration
- Filtrate
- Synthetic gypsum for wallboard or cement manufacture

Centhalia Power Plant FGD
- Contract cost $151,321,555
- Compliance Unit #2 12/31/01, Unit #1 12/31/02
- Absorber vessel-2 each 317 ftM4 SS @60 ft diameter and 120 ft high; four spray levels per absorber
- New stack 70 ft diameter and 470 ft high; 2, C276 SS clad liners @ 290° F in diameter
- 8 Warman slurry pumps total @ 55,000 GPM recycle each
- 1 Ball mill @ 41 tons per hour
- 2 Belt filters @ 46 tons per hour each