Air Quality Permit Applicability Assessment
Boiler Efficiency Project

Centralia, Washington

Prepared for:

TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, Washington 98531

September 2007

Project No. 012530

Geomatrix

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (TCG) operates the power plant near Centralia ("Centralia Plant" or "Plant") in Lewis County, Washington. Units 1 and 2 at the Centralia Plant are controlled circulation, radiant reheat, and divided steam generators. Pulverized coal is transported from eight mills and fired through eight elevations of tilting, tangential coal nozzles. An LNCFS level III low NOx firing system was installed on Unit 2 in July 2001 and on Unit 1 in July 2002. A limestone-based wet scrubber was installed on Unit 2 in October 2001 and on Unit 1 in July 2002.

Since the closure of its local mine ("TransAlta Centralia Mine" or "TCM") in 2006, TCG has been evaluating various sources of coal from the Powder River Basin (PRB) of Wyoming and Montana for use in its boilers at the Centralia Plant. TCG has burned blends of local and PRB coal in the past, but is now likely to burn 100 percent PRB coal. To address the specific characteristics of PRB coal, TCG is planning several safety and boiler efficiency projects. The boiler projects will be implemented during outages in the first quarters of 2008 and 2009.

The purpose of this report is to document the bases for our conclusion that TCG's plans to change sources of coal and improve the efficiency of the boilers do not trigger the requirement for minor or major new source review or applicability of any New Source Performance Standard.

1.1 ORGANIZATION

Chapter 2 provides a description of the proposed projects. These projects include efficiency projects that alter heat transfer components inside the boiler and safety-related, non-boiler projects. Note that TCG may not move forward with all of the projects being considered, but all are described and addressed in this analysis.

Because applicability of various regulatory programs is based primarily on emissions, in Chapter 3 we identify current and future potential hourly emissions and then past actual and projected future actual annual emissions from the boilers.

Chapter 4 addresses regulatory programs that potentially apply when an industrial source makes changes to an emissions unit. We begin with minor new source review for criteria and toxic air pollutants, whereby the Southwest Clean Air Agency (SWCAA) authorizes modifications through its Air Discharge Permit process. Because the criteria triggering applicability are similar, we next address the possibility that New Source Performance Standards ("NSPS") may be applicable after the boilers are improved.

Finally, we address whether the proposed changes trigger major stationary source review under the PSD permit process administered by the Washington State Department of Ecology (Ecology).

1.2 SUMMARY OF FINDINGS

This analysis concludes that the proposed projects are not subject to SWCAA or Ecology new source review because there are no increases in potential hourly emissions or increases in projected actual annual emissions. Furthermore, NSPS, Subpart Da does not apply because hourly potential emissions do not increase.

2.0 PROJECT DESCRIPTION

2.1 PHYSICAL DESCRIPTION OF BOILER PROJECTS

The slagging and fouling characteristics of PRB coal increase the heat rates of the boilers compared with TCM coal. TCG plans physical changes to the pressure parts in each boiler's convective pass that will improve heat transfer. No changes to the fuel delivery equipment, burners, combustion air system, or steam turbine are proposed. Also, as described below, the PRB coals are "cleaner" in several respects than local coals, e.g., lower sulfur, ash and nitrogen contents. Consequently, the proposed changes do not increase potential emissions. In short, the projects will allow the boilers to burn PRB coal more efficiently, but will not increase the boilers' potential steam generating capacity.

All pressure part changes will occur in the existing physical boundaries of the boiler furnace and structure. The new pressure parts have tube arrangements, sizes and materials selected to minimize ash deposition on convective surfaces. Ash deposition reflects combustion heat inside the boiler furnace and reduces the effective heat transfer from the combustion flue gas to the steam. This causes the flue gas exiting the boiler to reach its maximum allowable operating temperature of 900°F and a consequent drop in steam flow. The boiler changes will reduce the boiler susceptibility to ash deposition resulting in an increase in effective heat transfer, reduction in flue gas exit temperature and increase in steam flow to allow sustainable unit operation at net dependable capacity. The individual pressure part changes are discussed separately below. All pressure part changes apply to both Unit 1 and Unit 2 unless otherwise noted.

2.1.1 Reheater Replacement

The replacement reheater will have increased transverse spacing and platenized surfaces that minimize the "grip" that ash can get on tube surfaces. Together, these changes will maximize sootblower cleaning effectiveness on the tube assembly surface areas. The platenized rear pendant assembly will be increased in length to compensate for the reduced surface area from achieving the desired transverse spacing and platenized design. The reheater replacement will also include a new reheater outlet header.

The replacement front and rear reheater pendants will all be made of stainless steel tubing compared to the existing reheater pendants, which use a combination of various ferritic and stainless steel tubing in the front pendant and all stainless steel tubing in the rear pendant.

Stainless steel tubing has a greater range of allowable tube temperatures and has a higher resistance to ash deposition when compared to ferritic tubing.

Inconel 622 weld overlay will be applied to the exterior of reheater tubes where sootblowers are located in order to provide sootblower erosion protection.

2.1.2 Low Temperature Superheater (LTSH) Replacement

The replacement vertical pendant LTSH will consist of 268, 2 1/8" assemblies with SA-213 T12 material. This will replace the existing shorter, vertical pendant LTSH, which consists of 268 assemblies of 2" tubes of ferritic steel. The increased length of the replacement vertical pendant LTSH will provide greater heat transfer and result in a lower flue gas exit temperature.

Erosion shields will be installed on the LTSH tubing in areas where sootblowers are located in order to provide sootblower erosion protection.

2.1.3 Economizer Replacement

The economizer replacement in Unit 1 will consist of 268, 2" assemblies of SA-210C material. This will replace the existing Unit 1 economizer which consists of 268, 2" assemblies of SA-210A-1 material. (The Unit 2 economizer was previously replaced.)

Unit 1 and Unit 2 will both receive an additional economizer bank of bare tubing in the hopper area below the existing economizer. The additional lower economizer bank increases the heat transfer surface area and will further reduce the flue gas exit temperature. The additional lower economizer will consist of 236, 2" tube assemblies of SA-210C material. The existing economizer inlet header will be removed and a new 14" inlet header will be installed at the inlet of the additional lower economizer bank.

Erosion shields will be installed on the new upper economizer and lower economizers where required to provide sootblower erosion protection.

2.2 Miscellaneous Safety and Non-Pressure Boiler Changes

2.2.1 Pulverizer Protection

A set of piping, valves, fittings, instrumentation and control logic will be added to each coal pulverizer to allow the admission of high pressure steam into the pulverized coal fuel system to provide fire and explosion protection. During a fuel interruption event, the pulverizer protection system will supply high pressure steam to each pulverizer to inert the hazardous oxygen rich atmosphere inside the pulverizer and provide a medium to purge the residual pulverized coal into the furnace. The high pressure steam supply is taken from existing high pressure steam outlet headers and is supplied to each pulverizer in a header arrangement. The high pressure steam supply to each pulverizer has a flow measurement device, flow control valve, automatic block valve, manual valve, diffuser, condensate return system and associated instrumentation. The pulverizer protection will be controlled from the existing plant Distributed Control System (DCS).

2.2.2 Enhanced Sootblower Coverage

The enhanced sootblower project includes twenty new retractable steam sootblowers and eight new steam wallblowers for each unit. The additional sootblowers and wallblowers help reduce the slagging and fouling in the boiler furnace and convective heat transfer surfaces in order to maintain heat transfer effectiveness and lower the flue exit gas temperature. The new sootblowers are located in the convective pass between tube assemblies and the new wallblowers are located in the furnace. All new sootblowers and wallblowers will be operated from the existing boiler cleaning management control system. (TransAlta has informed Geomatrix that its boiler contractor has represented that they result in no increase in unit emissions.)

2.2.3 HydroJets Cleaning System

The HydroJet cleaning system is an on-line furnace cleaning system to maintain heat transfer effectiveness inside the furnace and lower the flue exhaust gas temperature. The HydroJet system for each boiler consists of six hydrojet panels, 26 heat flux sensors, a stand-alone control system, as well as associated auxiliary and ancillary equipment. Each hydrojet panel consists of a custom bent waterwall tube section that is mounted in the furnace waterwall and contains a robotically controlled high pressure water nozzle that operates from a computer controlled spray pattern on a cross-wall cleaning principle. (TransAlta has informed Geomatrix that its boiler contractor has represented that the HydroJets result in no increase in unit emissions.)

2.2.4 TIFI (Targeted In-Furnace Injection)

TIFI is a patented fireside furnace treatment technology. It consists of injecting a chemical reagent, magnesium hydroxide, in the boiler furnace at computer determined injection locations. The magnesium hydroxide is in the form of a slurry that is atomized at the boiler furnace injectors with compressed air and an injection nozzle. The injected additive reacts with the crystal structure of forming slag and existing slag deposits, effectively reducing the strength of slag in the furnace. The weakened crystal structure and bond between the slag and boiler tubes allows for more effective cleaning from the furnace cleaning equipment (Sootblowers and HydroJets). TIFI has been installed on an experimental basis in both Unit 1 and Unit 2 in Q4 2006. (TransAlta has informed Geomatrix that its boiler contractor has represented that TIFI results in no increase in unit emissions.)

3.0 AIR EMISSIONS

Although the projects described in Chapter 2 represent physical changes to the boilers, there is no reason to expect that the furnace firing rates or boiler emissions will increase as a result of the improved heat transfer that will result from these physical changes. To evaluate the "common sense" expectation that the change to PRB coals and boiler efficiency improvements will not increase the Plant's emissions, TCG retained Geomatrix to scrutinize historic emissions and assess emission changes with PRB coals and the proposed boiler projects. As discussed further below, TCG also retained Alstom Power, Inc. and Black & Veatch to model future emission rates, considering proposed boiler improvements and Powder River Basin coals.

As TCM coal is being phased out, TCG has been burning a variety of PRB coals. In 2007, for example, more than half the coal burned at the Centralia Plant has been PRB coals, including coal from SCM (Spring Creek Mine), KSCM (Spring Creek with kaolin), RWM (Rawhide Mine), CAM (Caballo Mine), CDM (Cordero Mine), JRM (Jacobs Ranch Middle Wyodak), BKM (Buckskin Mine), and ABM (Absaloka Mine). One or both units have operated on 100 percent of each of these PRB coals (except ABM, at 40%) at some time during 2007. Clearly, the Centralia Plant has the capability of burning these PRB coals now, and continued use of these coals in the future will not increase potential hourly emissions Proposed boiler projects will improve heat transfer when using PRB coals and are, therefore, desirable to increase generation, but the projects are not required to enable the Centralia plant to operate on the PRB coals.

Table 1 compares the key characteristics of the TCM coal that has historically been the primary coal with those of Power River Basin coals being evaluated. Note also that the average Power River Basin coal has eight percent higher Btu content than the average TCM coal.

Consistent with historic annual emission inventory practices at the Plant, our annual emissions estimates do not include excess emissions associated with startup, shutdown, or upset conditions. Those conditions are excluded from NSPS consideration, and are generally not relevant to examinations of hourly potential to emit. While such conditions are sometimes included in calculating annual emissions, the purpose of evaluating annual emissions in this assessment is to determine the change in emissions after the boiler improvement projects. Because TCG does not expect the projects to have any effect on the historic frequency or extent of startups, shutdowns, or upsets, emissions associated with those events would simply cancel out of the past and future emissions comparison.

3.1 HOURLY EMISSIONS

Current and historic emissions of NOx, CO, and SO2 are provided by Continuous Emission Monitoring Systems (CEMS) installed on each boiler stack. Particulate matter and volatile organic carbon (VOC) emissions are based on boiler firing rate and emission factors (lb/MMBtu) derived from unit-specific source tests.

To determine current potential emissions of NOx, CO, and SO2, Geomatrix examined valid hourly mass emission rates reported by the CEMS from 2003 through 2006. We identified the maximum hourly emission rate of NOx, CO, and SO2, and used that emission rate as a conservative indicator of the current potential hourly emission rate.

To estimate particulate matter and volatile organic carbon (VOC) emissions, emission factors (lb/MMBtu) derived from annual source tests were applied to the maximum recorded hourly firing rate for each boiler for each year from 2003 through 2006. Note that PM emissions are based on the measured filterable component (Method 5). PM10 emissions are based on the sum of (1) the measured filterable component derived by Method 5 multiplied by 0.67 (per AP-42 Table 1.1-6) and (2) the measured condensable fraction (Method 202).

Black & Veatch evaluated the emission implications of the boiler improvement projects and the range of PRB coals being considered. Black & Veatch's report predicted mass emission rates (lb/hr) and emission factors (lb/MMBtu) for NOx, CO, and SO2 based on the predicted firing rate required to achieve 663 net MW electrical generation and on the chemistry and heat value of the coals. A generation rate of 663 net MW has been predicted to be the post-Project Maximum Potential Sustainable Load (see Black & Veatch, Table 5). Accordingly, they are appropriate as estimates of future potential hourly emissions.

From a common sense perspective, no increase in hourly emissions of criteria or toxic air pollutants is to be expected because the same coals to be burned in the future have been burned already this year and the heat transfer upgrades do not increase the firing rate of the boilers. In fact, improved heat transfer is intended to reduce the firing rate of PRB coals. Table 2 compares firing rates (MMBtu/hr) over the last four years with those predicted by Black & Veatch. This comparison demonstrates that predicted hourly firing rates will be less than the average firing rates observed over the period 2003-2006, and substantially lower than the maximum hourly firing rate over this period. Similarly, Table 3 compares maximum historic hourly coal combustion (tons/hour) with those predicted by Black & Veatch. Again, hourly coal combustion is expected to be lower than has occurred in the last four years.

Table 4 summarizes current and post-project potential hourly emissions. Lower NOx, SO2, and PM/PM10 emissions would be expected based on the lower average nitrogen, sulfur, and ash content of the PRB coals (see Table 1 comparison with TCM coal).

The Black & Veatch modeling indicates that, at full load conditions, there would be no significant difference in furnace temperature across the coals that would result in a significant change in thermal NOx production. Consequently, the nitrogen content of the coals has a direct bearing on NOx emissions. Although uncontrolled SO2 and PM emissions would also be expected to decrease with the lower sulfur and ash content in Powder River Basin coal, a direct correlation would not be expected because the efficiencies of the SO2 scrubbers and ESPs vary with uncontrolled SO2 and PM load.

Black & Veatch acknowledges that carbon monoxide emissions predictions are more complicated. Besides the carbon content of the coal, the CO emission rate is highly dependent on the stoichiometry at the burners and throughout the boiler, residence time in the boiler, coal oxygen content, and fuel ash content.

Similarly, we have no reason to expect potential VOC, PM, PM10, or toxic air pollutant emission factors (lb/MMBtu) to increase. Based on predicted hourly fuel burn rates (expressed as MMBtu/hr or tons coal/hour) that are lower than those observed from 2003-2006 and emission factors that remain the same, hourly mass emissions of VOCs, particulate matter, and toxic air pollutants would decrease in proportion to the heat input.

While we have not calculated the specific changes in emissions of toxic air pollutants, future fuel burn rates (MMBtu/hr and tons coal/hour) are lower than the maximum hourly rates documented in the baseline years. AP42 emission factors used in the Plant's annual emission inventories ("AEIs") are based on lb/ton coal, and future maximum coal combustion is lower than in the baseline years. EPRI emission factors used in the AEIs are based on lb/MMBtu, and the heat input will be lower than that documented in the baseline years. Furthermore, all the coals currently under consideration have already been combusted at the Centralia Plant, and coal-specific toxic air pollutant emissions would decrease with the lower heat input resulting from efficiency improvements. In short, we anticipate potential hourly emissions of criteria and toxic air pollutants to decrease with the boiler improvement projects.

3.2 Annual Emissions

As noted in Section 3.1, Geomatrix obtained hourly mass emission rates reported by the NOx, CO, and SO2 CEMS from 2003 through 2006.[1] We then calculated rolling 24-month total emissions for each pollutant for each boiler.[2] We summed the 24-month totals for each boiler, and divided by two to determine an average annual emission rate month by month. We selected the highest annual average emissions (in tons) to establish an initial baseline for NOx, CO, and SO2. As required by EPA, the baseline period is the same for both boilers.

Consistent with our approach to calculating hourly PM, PM10, and VOC emissions, we applied the annual source test results to each month and applied monthly total firing rates (MMBtu/month) to determine monthly emissions from 2003 through 2006. We determined 24-month rolling average PM, PM10, and VOC emissions, and selected the maximum 24-month annual average as the baseline emission rate.

Table 5 presents an adjusted baseline emission rate that accommodates the exclusion from "Projected Actual Emissions" provided at 40 CFR 52.21(b)(41) for post-project emissions that a unit could have accommodated before the project:

> (ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:
> (c) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;

Geomatrix calculated monthly total gross power generation for each unit and scaled up the annual baseline emissions by multiplying by the ratio of maximum potential power generation (1,495 MW total for both units) to the gross electrical generation reported during the pollutant specific baseline periods.

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[1] The baseline period actually extends back as far as May 2002 because implementation of the Fuel Conversion project had commenced at that time. This assessment includes CO data as far back as May 2002.
[2] This Geomatrix baseline and the preliminary baseline previously provided by TransAlta are based on emission reports submitted for the Acid Rain Program. However, the Geomatrix baseline period excludes artificially high substituted data for hours when CEMS data were not available or were erroneous. Geomatrix substituted a generation-based interpolated value for those hours. Thus, the baseline emissions presented here are lower than those previously identified.

Based on its experience, TCG's production plan estimates a maximum capacity factor of 93% with no outages, which is an appropriate basis for determining potential annual emissions. Future potential annual emissions are therefore based on the predicted potential hourly emissions (Table 4) and the assumption that the boilers operate at their maximum rate for 8,160 hours per year (93% capacity factor). Table 5 presents the adjusted baseline and the future annual emissions based on TCG's estimated maximum achievable capacity factor (Maximum Sustainable Potential Load for 93 percent of the year).

4.0 REGULATORY ANALYSIS

This section identifies and discusses air quality regulations that potentially apply when physical or operational changes are made to emission units such as the two boilers at the Centralia Plant. Based on the emissions information presented in Chapter 3, we find that none of these programs apply and that the proposed projects are not subject to air permit requirements.

4.1 MINOR NEW SOURCE REVIEW

SWCAA Regulation 400 establishes General Regulations for Air Pollution Sources that apply in Lewis County. SWCAA 400-409 requires that stationary sources (such as the Centralia Plant) submit an Air Discharge Permit application for "*all new installations, modifications, changes, and alterations to process and emission control equipment consistent with the definition of 'new source'.*" SWCAA 400-030(72) defines a "new source" as one of the following:

> *(a) The construction or modification of a "stationary source" that increase the amount of any air contaminant emitted by such "stationary source" or that results in the emission of any air contaminant not previously emitted;*
>
> *(b) Any other project that constitutes a "new source" under the Federal Clean Air Act;*
>
> *(c) Restart of a "stationary source" after permanent shutdown;*
>
> *(d) The installation or construction of a new "emission unit"; or*
>
> *(e) Relocation of a "stationary source" to a new location, except in the case of portable sources operating under a valid permit as provide in SWCAA 400-110(6).*

The only definition of new source that potentially applies to the planned projects at the Centralia Plant is (a) ("modification" of a stationary source). The term "modification" is precisely defined in SWCAA 400-030 as:

> *"any physical change in, or change in the method of operation of, a "stationary source" that increases the amount of any air contaminant emitted by such "stationary source" or that results in the emissions of any air contaminant not previously emitted. The term modification shall be construed consistent with the definitions of modification in Section 7411, Title 42, United States Code, and with rules implementing that section."*

This definition mirrors the state definition of "modification" in the Department of Ecology's regulations at WAC 173-400-030(47). Both definitions require "modification" to be consistent with rules implementing the federal New Source Performance Standards ("NSPS"). As defined in 40 CFR 60.14 (b), "emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable." In other words, SWCAA's and Ecology's rules adopt an increase in kilogram or pound per hour test to determine whether a project is a "modification" requiring a permit. Furthermore, EPA's NSPS guidance has consistently referenced changes in the maximum throughput or capacity of a unit when determining whether there is an "increase" in hourly emissions.

Table 4 demonstrates that there will be no increase in the maximum hourly emissions from Unit 1 or Unit 2 as a result of the increase in use of PRB coal or the boiler efficiency projects.[3] Consequently, the boilers will not be "modified" under the definition applied when determining applicability of SWCAA's minor new source review program, and the projects are not subject to SWCAA's preconstruction permitting requirements. Similarly, the fact that there will be no increase in the maximum hourly emissions of toxic air pollutants compared with historic and current emissions means that minor new source review will not be triggered based on toxic air pollutants. Furthermore, the NSPS "fuel switching exemption" would apply because the units were "capable of accommodating" PRB coal prior to September 18, 1978.

4.2 NEW SOURCE PERFORMANCE STANDARDS

NSPS are nationally uniform standards applied to specific categories of stationary sources that are constructed, modified, or reconstructed after the standard was proposed. NSPSs are found in Title 40, Part 60 of the Code of Federal Regulations (CFR).

NSPS, Subpart Da applies to emissions of NOx, PM, SO2, and Hg from all electric utility steam generating units for which construction, modification, or reconstruction is commenced after September 18, 1978, and that have a maximum design heat input from fossil fuel greater than 250 million Btu per hour. Units 1 and 2 have a design heat input greater than 250 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968. As discussed in Section 4.1, the planned boiler improvement projects and increased use of PRB coal do not constitute a modification because they do not result in an increase in potential hourly emissions of NOx, PM, SO2, or Hg. Furthermore, the NSPS "fuel switching exemption" would apply because the units were "capable of accommodating" PRB coal prior to September 18, 1978. Therefore, this regulation does not apply to the Centralia Plant Units 1 and 2.

4.3 PSD MAJOR NEW SOURCE REVIEW

The Centralia Plant is a major stationary source (as defined in PSD regulations) because it emits more than 100 tons per year of a regulated air pollutant. For a major stationary source, the PSD permit process is triggered whenever a modification results in net emission increases that exceed specified significant emission thresholds. In contrast to minor new source review and NSPS, a modification for PSD purposes is based on the change in annual emissions. The change in emissions is calculated by subtracting baseline emissions ("Baseline Actual Emissions") for the affected unit(s) from anticipated emissions after the Project is implemented. Modifications to the affected units (in this case, Units 1 and 2) that increase net emissions above prescribed PSD Significant Emission Rates (SERs) are considered "major modifications" subject to the PSD permitting process.

For Electric Utility Steam Generating Units, the Baseline Actual Emissions are the average annual actual emissions from any consecutive 24-month period within the five years preceding the commencement of construction of the modification. A different 24-month period may be used for each pollutant. The Baseline Actual Emissions may also include emissions that the source was capable of emitting had business potential been fully realized (i.e., emissions based on full production).

For a modified unit, the future emissions may be based on Projected Actual Emissions or on the modified unit's potential to emit (PTE). The Black & Veatch modeling utilized estimates of "maximum potential sustainable load" (steam flow and equivalent MW rating) to estimate emissions that TCG believes represent hourly PTE.

Table 5 summarizes the adjusted annual baseline and future potential emissions with Units 1 and 2 operating 8,160 hours (93 percent capacity factor) at the predicted hourly emissions displayed in Table 4. The adjusted baseline accounts for unused business potential, and has been estimated by scaling up the annual baseline emissions by the ratio of the maximum potential gross power generation (1,495 MW) to the actual gross electrical generation during that baseline period.[4] As indicated in Table 5, all of the projected annual emission rates for PSD pollutants are lower than the corresponding baseline values. This comparison confirms that the PSD permit process is not triggered by a conversion to 100 percent PRB coal and the planned boiler efficiency projects.

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[3] Note that the NSPS "fuel switching exemption" would also exempt the burning of PRB coal and related safety and efficiency changes from SWCAA's ADP requirement.

[4] The gross generation capacity of the plant (1,495 MW) has not changed over the course of the baseline period.

To avoid raising any question of PSD applicability, we recommend that TCG operate Units 1 and 2 in the future with annual emissions no greater than the adjusted baseline emissions (displayed in Table 5) plus the SERs. This sum is presented in Table 6. Operating under those limits also avoids the need to determine the applicability of the "fuel switching exemption" and separating emissions attributable to the change in coals from emissions due to boiler changes.

In summary, the planned boiler improvement projects and increased use of PRB coal do not constitute a PSD major modification because they do not result in an increase in annual emissions. Furthermore, the PSD "fuel switching exemption" (patterned on the NSPS exemption) would apply because the units were "capable of accommodating" PRB coal prior to January 6, 1975. Therefore, the PSD regulation does not apply to these projects or the use of PRB coal.

Tables

TABLE 1

SUMMARY OF KEY TCM AND PRB COAL CHARACTERISTICS

TransAlta Centralia Generation, LLC
Centralia, Washington

	TransAlta Centralia Mine Coal				Powder River Basin Coal		
	Low Sulfur (<1.2%)		High Sulfur (>1.2%)				
	Mean	Max	Mean	Max	Mean	Max	From
Btu/lb	7,681	8,113	7,930	8,121	8,414	8,800	Jacobs Ranch Upper Wyodak
Sulfur (%)	0.69	0.84	1.89	2.14	0.40	0.88	Jacobs Ranch Upper Wyodak
Ash (%)	15.44	16.44	14.43	16.46	6.21	13.04	Special K Fuel
Carbon (%)	44.95	47.37	45.63	46.45	49.11	51.26	Jacobs Ranch Upper Wyodak
Nitrogen (%)	0.76	0.80	0.71	0.75	0.67	0.8	Jacobs Ranch Upper Wyodak

Characteristics on an "as received" basis.

TABLE 2

SUMMARY OF BASELINE AND PREDICTED HEAT INPUT (MMBTU/HR)

TransAlta Centralia Generation, LLC
Centralia, Washington

	Unit 1		Unit 2	
	Average	**Maximum**	**Average**	**Maximum**
2003	7,348	9,321	7,408	9,377
2004	7,612	9,697	7,399	8,588
2005	7,743	8,963	7,765	9,189
2006	6,058	8,562	6,625	9,207
Average	7,190	9,136	7,299	9,090
Maximum	7,743	9,697	7,765	9,377
Predicted				
Average	7,034		7,034	
Range	6,989-7,071		6,989-7,071	

1 Average and "range" refer to the average and range of heat input predicted for various PRB coals.

TABLE 3

MAXIMUM HOURLY COAL CONSUMPTION (tons)

TransAlta Centralia Generation, LLC
Centralia, Washington

	2003	2004	2005	2006	
Unit 1	455	574	498	455	Source: AEI
Unit 2	550	500	488	506	Source: AEI
Projected	443	443	443	443	Source: B&V, for Special K

TABLE 4

CURRENT AND PREDICTED HOURLY POTENTIAL EMISSION RATES (pounds)

TransAlta Centralia Generation, LLC
Centralia, Washington

	NOx	CO	SO2	PM	PM10	VOC
Unit 1 maximum hourly emissions	3,733	18,538	3,366	54	108	4.5
Unit 1 future potential hourly emissions	1,859	621	704	25	61	3.5
Change	-1,874	-17,917	-2,662	-29	-47	-1.0
Unit 2 maximum hourly emissions	2,841	12,084	4,327	55	156	26
Unit 2 future potential hourly emissions	1,859	621	704	24	78	12
Change	-982	-11,463	-3,623	-31	-78	-14

1 - NOx emissions based on CEMS data from January 2003 through March 2006 (unit 1 max July 2004, unit 2 max October 2004): Future emission rate based on B&V projection for Jacobs Ranch, Upper Wyodak coal.

2 - CO emissions based on CEMS data from May 2002 through December 2006. Future emissions based on B&V projection for Jacobs Ranch, Upper Wyodak coal. The maximum values in this table reflect actual CEMS data, but may reflect abnormal operating conditions. Additional analysis of the CO CEMS data recorded from May 2002 through 2006 indicate that approximately two percent of the hourly observations exceed 3,000 pounds per hour. More than 19 percent of the observations from Unit 1 and 36 percent of the observations from Unit 2 exceed the 621 pounds CO per hour predicted by Black & Veatch.

3 - SO2 emissions based on CEMS data from January 2003 through March 2006. (Unit 1 max Dec.2004, unit 2 max Oct.2004) Future emission rate based on B&V projection for Jacobs Ranch, Upper Wyodak coal.

4 - Current PM emissions based on Methods 5 source tests and 2003-2006 firing rates. Future emissions based on highest B&V projected boiler firing rate and an emission factor (lb/MMBtu) derived by averaging Method 5 source tests conducted in 2005 and 2006.

5 - Current PM10 emissions based on Methods 5 and 202 source tests and 2003-2006 firing rates. Future emissions based on highest B&V projected boiler firing rate and an emission factor (lb/MMBtu) derived by averaging PM10 source tests conducted in 2005 and 2006.

6 - VOC emissions based on facility source tests and maximum hourly firing rates. Future emissions based on highest B&V projected boiler firing rate and 2005 and 2006 unit source tests. Note that the 2006 VOC source test result for Unit 2 is much higher than any previous test for either Unit, and may overestimate actual hourly emissions.

TABLE 5

BASELINE AND PROJECTED ANNUAL POTENTIAL EMISSIONS

TransAlta Centralia Generation, LLC
Centralia, Washington

	NOx	CO	SO2	PM	PM10	VOC
Baseline boiler emissions (tons/yr)	15,695	5,778	7,031	298	754	44
Dates for Baseline Period (24 months)	12/1/03-11/31/05	9/1/02-08/31/04	1/1/03-12/31/04	1/1/04-12/31/05	1/1/04-12/31/05	1/1/05-12/31/06
MWhr Generated during Baseline (MWhr/yr)	11,130,793	11,548,694	11,381,503	11,057,877	11,057,877	8,916,308
Gross MWhr Potential (MWhr/yr)	13,096,200	13,096,200	13,096,200	13,096,200	13,096,200	13,096,200
Adjusted baseline (tons/yr)	18,467	6,552	8,091	353	892	64
Future potential emissions (tons/yr)	15,169	5,067	5,744	200	568	62
Change (tons/yr)	-3,298	-1,485	-2,346	-153	-325	-2
Significant Emission Rate (tons/yr)	40	100	40	25	15	40

1 - NOx emissions are based on the highest 24 month period of CEMS data from January 2003 through March 2006 (Dec.2003 - Nov.2005). Future emissions based on 8,160 hours of operation at the future potential hourly emission rate identified in Table 4.
2 - CO emissions are based on the highest 24 month period of CEMS data from May 2002 through December 2006 (Sept. 2002 - August.2004). Future emissions based on 8,160 hours of operation at the future potential hourly emission rate identified in Table 4.
3 - SO2 emissions are based on the highest 24 month period of CEMS data from January 2003 through March 2006 (Jan.2003 - Dec.2004). Future emissions based on 8,160 hours of operation at the future potential hourly emission rate identified in Table 4.
4 - PM, PM10, and VOC emissions are based on the highest 24 month period of emission calculations from January 2003 through December 2006. Future emissions based on 8,160 hours of operation at the future potential hourly emission rate identified in Table 4. Note that the unusually high emission rate resulting from a 2006 source test of Unit 2 leads to a much higher future predicted VOC rate than would be expected based on the other test results. It is likely that the actual change in annual VOC emissions will be much smaller than these calculations suggest.
5 - Annual potential Gross MWhr generation based on 1,495 MW gross for both units.
6 - Unused business potential based on baseline boiler emissions and the ratio of gross power generated during baseline to the potential gross power that could have been generated.

TABLE 6

FUTURE ACTUAL EMISSION RATES ENSURING PSD DOES NOT APPLY

TransAlta Centralia Generation, LLC
Centralia, Washington

	NOx	CO	SO2	PM	PM10	VOC
Adjusted baseline boiler emissions (tons/yr)[1]	18,467	6,552	8,091	353	892	64
Significant Emission Rate (tons/yr)	40	100	40	25	15	40
Total future emission rate ensuring PSD does not apply	18,507	6,652	8,131	378	907	104

1 Baseline adjusted for unused capacity during baseline period .